Expenses and Other and Income Tax Expense (Benefit) changed between years as follows:

- **Other Operation and Maintenance** expenses increased $49 million primarily due to the following:
  - A $47 million increase in transmission expenses primarily due to PJM transmission services including the annual formula rate true-up. This increase was partially offset in Retail Margins above.
  - A $9 million increase due to a charitable contribution to the AEP Foundation.
  - A $5 million increase in insurance and rate case expenses. This increase was partially offset in Retail Margins above.
  - A $5 million increase in customer service expenses primarily due to demand-side management expenses. This increase was partially offset in Retail Margins above.

  These increases were partially offset by:
  - A $9 million decrease in steam generation expenses at Rockport Plant primarily due to a decrease in various maintenance activities, employee-related expenses and amortization of terminated Indiana generation riders, partially offset by the NSR settlement in 2019. This net decrease was partially offset in Retail Margins above.
  - A $9 million decrease in generation expenses at Cook Plant primarily due to a decrease in various maintenance activities.
- **Depreciation and Amortization** expenses increased $58 million primarily due to increased depreciation rates approved in 2018 and a higher depreciable base. This increase was partially offset in Retail Margins above.
- **Taxes Other Than Income Taxes** increased $6 million due to property taxes driven by an increase in utility plant.
- **Interest Expense** decreased $6 million primarily due to the reissuance of long-term debt at lower interest rates in 2018, partially offset by higher long-term debt balances.
- **Income Tax Expense (Benefit)** decreased $40 million primarily due to increased amortization of Excess ADIT not subject to normalization requirements, a decrease in state tax expense and a decrease in pretax book income. This decrease was partially offset in Gross Margin above.

REPORT OF INDEPENDENT REGISTERED PUBLIC ACCOUNTING FIRM

To the Board of Directors and Shareholder of
Indiana Michigan Power Company

Opinion on the Financial Statements

We have audited the accompanying consolidated balance sheets of Indiana Michigan Power Company and its subsidiaries (the "Company") as of December 31, 2019 and 2018, and the related consolidated statements of income, of comprehensive income (loss), of changes in common shareholder's equity and of cash flows for each of the three years in the period ended December 31, 2019, including the related notes (collectively referred to as the "consolidated financial statements"). In our opinion, the consolidated financial statements present fairly, in all material respects, the financial position of the Company as of December 31, 2019 and 2018, and the results of its operations and its cash flows for each of the three years in the period ended December 31, 2019 in conformity with accounting principles generally accepted in the United States of America.

Change in Accounting Principle

As discussed in Note 13 to the consolidated financial statements, the Company changed the manner in which it accounts for leases in 2019.

Basis for Opinion

These consolidated financial statements are the responsibility of the Company's management. Our responsibility is to express an opinion on the Company's consolidated financial statements based on our audits. We are a public accounting firm registered with the Public Company Accounting Oversight Board (United States) (PCAOB) and are required to be independent with respect to the Company in accordance with the U.S. federal securities laws and the applicable rules and regulations of the Securities and Exchange Commission and the PCAOB.

We conducted our audits of these consolidated financial statements in accordance with the standards of the PCAOB. Those standards require that we plan and perform the audit to obtain reasonable assurance about whether the consolidated financial statements are free of material misstatement, whether due to error or fraud. The Company is not required to have, nor were we engaged to perform, an audit of its internal control over financial reporting. As part of our audits we are required to obtain an understanding of internal control over financial reporting but not for the purpose of expressing an opinion on the effectiveness of the Company's internal control over financial reporting. Accordingly, we express no such opinion.

Our audits included performing procedures to assess the risks of material misstatement of the consolidated financial statements, whether due to error or fraud, and performing procedures that respond to those risks. Such procedures included examining, on a test basis, evidence regarding the amounts and disclosures in the consolidated financial statements. Our audits also included evaluating the accounting principles used and significant estimates made by management, as well as evaluating the overall presentation of the consolidated financial statements. We believe that our audits provide a reasonable basis for our opinion.

/s/ PricewaterhouseCoopers

Columbus, Ohio
February 20, 2020

We have served as the Company's auditor since 2017.

MANAGEMENT'S REPORT ON INTERNAL CONTROL OVER FINANCIAL REPORTING

The management of Indiana Michigan Power Company and Subsidiaries (I&M) is responsible for establishing and maintaining adequate internal control over financial reporting as such term is defined in Rule 13a-15(f) and 15d-15(f) under the Securities Exchange Act of 1934, as amended. I&M's internal control is a process designed to provide reasonable assurance regarding the reliability of financial reporting and the preparation of financial statements for external purposes in accordance with generally accepted accounting principles.

Because of its inherent limitations, internal control over financial reporting may not prevent or detect misstatements. Also, projections of any evaluation of effectiveness to future periods are subject to the risk that controls may become inadequate because of changes in conditions, or that the degree of compliance with the policies or procedures may deteriorate.

Management assessed the effectiveness of I&M's internal control over financial reporting as of December 31, 2019. In making this assessment, management used the criteria set forth by the Committee of Sponsoring Organizations of the Treadway Commission (COSO) in Internal Control – Integrated Framework (2013). Based on management's assessment, management concluded I&M's internal control over financial reporting was effective as of December 31, 2019.

This annual report does not include an audit report from PricewaterhouseCoopers LLP, I&M's registered public accounting firm regarding internal control over financial reporting pursuant to the Securities and Exchange Commission rules that permit I&M to provide only management's report in this annual report.

INDIANA MICHIGAN POWER COMPANY AND SUBSIDIARIES
CONSOLIDATED STATEMENTS OF INCOME
For the Years Ended December 31, 2019, 2018 and 2017
(in millions)

	Years Ended December 31,		
	2019	**2018**	**2017**
REVENUES			
Electric Generatıon, Transmissıon and Dıstrıbutıon	$ 2,222 1	$ 2,272 6	$ 2,042 5
Sales to AEP Affilıates	10.5	22.1	1 8
Other Revenues - Affilıated	63 4	63.4	62 6
Other Revenues - Nonaffiliated	10 7	12 6	14 3
TOTAL REVENUES	2,306 7	2,370 7	2,121 2
EXPENSES			
Fuel and Other Consumables Used for Electric Generatıon	190 6	318 3	295 1
Purchased Electrıcıty for Resale	232 3	221.8	152 2
Purchased Electricity from AEP Affilıates	214 9	237.9	223 9
Other Operation	641 2	585 4	591 3
Maıntenance	231 2	238 1	208 4
Depreciatıon and Amortızatıon	350 6	293 1	210 9
Taxes Other Than Income Taxes	105 1	98 9	92 2
TOTAL EXPENSES	1,965 9	1,993 5	1,774 0
OPERATING INCOME	340.8	377 2	347 2
Other Income (Expense):			
Other Income	18 2	19 2	25 6
Non-Servıce Cost Components of Net Perıodıc Benefit Cost	17.7	18.1	6.1
Interest Expense	(117 9)	(124 1)	(110 8)
INCOME BEFORE INCOME TAX EXPENSE (BENEFIT)	258 8	290 4	268 1
Income Tax Expense (Benefit)	(10 6)	29.1	81 4
NET INCOME	$ 269 4	$ 261 3	$ 186 7

The common stock of I&M ıs wholly-owned by Parent

See Notes to Fınancıal Statements of Regıstrants begınnıng on page 156.

INDIANA MICHIGAN POWER COMPANY AND SUBSIDIARIES
CONSOLIDATED STATEMENTS OF COMPREHENSIVE INCOME (LOSS)
For the Years Ended December 31, 2019, 2018 and 2017
(in millions)

	Years Ended December 31,		
	2019	2018	2017
Net Income	$ 269 4	$ 261.3	$ 186 7
OTHER COMPREHENSIVE INCOME (LOSS), NET OF TAXES			
Cash Flow Hedges, Net of Tax of $0 4, $0 4 and $0 7 in 2019, 2018 and 2017, Respectively	1 6	1 6	1 3
Amortization of Pension and OPEB Deferred Costs, Net of Tax of $0, $0 and $0 in 2019, 2018 and 2017, Respectively	(0 2)	—	—
Pension and OPEB Funded Status, Net of Tax of $0 2, $(0 2) and $1 5 in 2019, 2018 and 2017, Respectively	0 8	(0 6)	2 8
TOTAL OTHER COMPREHENSIVE INCOME	2 2	1 0	4 1
TOTAL COMPREHENSIVE INCOME	$ 271 6	$ 262 3	$ 190 8

See Notes to Financial Statements of Registrants beginning on page 156.

INDIANA MICHIGAN POWER COMPANY AND SUBSIDIARIES
CONSOLIDATED STATEMENTS OF CHANGES IN COMMON SHAREHOLDER'S EQUITY
For the Years Ended December 31, 2019, 2018 and 2017
(in millions)

	Common Stock	Paid-in Capital	Retained Earnings	Accumulated Other Comprehensive Income (Loss)	Total
TOTAL COMMON SHAREHOLDER'S EQUITY – DECEMBER 31, 2016	$ 56 6	$ 980.9	$ 1,130.5	$ (16 2)	$ 2,151 8
Common Stock Dividends			(125 0)		(125 0)
Net Income			186 7		186 7
Other Comprehensive Income				4 1	4 1
TOTAL COMMON SHAREHOLDER'S EQUITY – DECEMBER 31, 2017	56 6	980 9	1,192 2	(12 1)	2,217 6
Common Stock Dividends			(124 7)		(124 7)
ASU 2018-02 Adoption			0 3	(2 7)	(2.4)
Net Income			261 3		261 3
Other Comprehensive Income				1 0	1 0
TOTAL COMMON SHAREHOLDER'S EQUITY – DECEMBER 31, 2018	56 6	980 9	1,329 1	(13 8)	2,352.8
Common Stock Dividends			(80 0)		(80.0)
Net Income			269 4		269.4
Other Comprehensive Income				2 2	2 2
TOTAL COMMON SHAREHOLDER'S EQUITY – DECEMBER 31, 2019	$ 56.6	$ 980.9	$ 1,518 5	$ (11 6)	$ 2,544.4

See Notes to Financial Statements of Registrants beginning on page 156

INDIANA MICHIGAN POWER COMPANY AND SUBSIDIARIES
CONSOLIDATED BALANCE SHEETS
ASSETS
December 31, 2019 and 2018
(in millions)

	December 31, 2019	December 31, 2018
CURRENT ASSETS		
Cash and Cash Equivalents	$ 2.0	$ 2 4
Advances to Affiliates	13 2	12 7
Accounts Receivable·		
Customers	53 6	63 1
Affiliated Companies	53.7	75 0
Accrued Unbilled Revenues	2.5	3 6
Miscellaneous	0.3	1 4
Allowance for Uncollectible Accounts	(0.6)	(0 1)
Total Accounts Receivable	109.5	143 0
Fuel	56.2	37 3
Materials and Supplies	171.3	167.3
Risk Management Assets	9.8	8 6
Accrued Tax Benefits	—	26.6
Regulatory Asset for Under-Recovered Fuel Costs	3 0	—
Accrued Reimbursement of Spent Nuclear Fuel Costs	24.0	7 9
Prepayments and Other Current Assets	14 0	24 6
TOTAL CURRENT ASSETS	403.0	430.4
PROPERTY, PLANT AND EQUIPMENT		
Electric		
Generation	5,099 7	4,887 2
Transmission	1,641.8	1,576.8
Distribution	2,437 6	2,249.7
Other Property, Plant and Equipment (Including Coal Mining and Nuclear Fuel)	632 6	583.8
Construction Work in Progress	382.3	465 3
Total Property, Plant and Equipment	10,194.0	9,762 8
Accumulated Depreciation, Depletion and Amortization	3,294 3	3,151 6
TOTAL PROPERTY, PLANT AND EQUIPMENT – NET	6,899 7	6,611 2
OTHER NONCURRENT ASSETS		
Regulatory Assets	482.1	512.5
Spent Nuclear Fuel and Decommissioning Trusts	2,975.7	2,474 9
Long-term Risk Management Assets	0.1	0 6
Operating Lease Assets	294.9	—
Deferred Charges and Other Noncurrent Assets	181 9	193.0
TOTAL OTHER NONCURRENT ASSETS	3,934 7	3,181.0
TOTAL ASSETS	$ 11,237 4	$ 10,222 6

See Notes to Financial Statements of Registrants beginning on page 156

INDIANA MICHIGAN POWER COMPANY AND SUBSIDIARIES
CONSOLIDATED BALANCE SHEETS
LIABILITIES AND COMMON SHAREHOLDER'S EQUITY
December 31, 2019 and 2018
(dollars in millions)

	December 31,	
	2019	2018
CURRENT LIABILITIES		
Advances from Affiliates	$ 114.4	$ 1 1
Accounts Payable:		
General	169.4	174 7
Affiliated Companies	68 4	70 2
Long-term Debt Due Within One Year – Nonaffiliated (December 31, 2019 and 2018 Amounts Include $86 1 and $76 8 Respectively, Related to DCC Fuel)	139 7	155 4
Risk Management Liabilities	0 5	0 3
Customer Deposits	39 4	38 0
Accrued Taxes	112 4	90 7
Accrued Interest	36 2	37 3
Obligations Under Operating Leases	87 3	—
Regulatory Liability for Over-Recovered Fuel Costs	6 1	27.4
Other Current Liabilities	109 6	103 0
TOTAL CURRENT LIABILITIES	883.4	698 1
NONCURRENT LIABILITIES		
Long-term Debt – Nonaffiliated	2,910 5	2,880 0
Long-term Risk Management Liabilities	—	0 1
Deferred Income Taxes	979 7	948 0
Regulatory Liabilities and Deferred Investment Tax Credits	1,891.4	1,574 5
Asset Retirement Obligations	1,748 6	1,681 3
Obligations Under Operating Leases	211 6	—
Deferred Credits and Other Noncurrent Liabilities	67 8	87 8
TOTAL NONCURRENT LIABILITIES	7,809 6	7,171.7
TOTAL LIABILITIES	8,693 0	7,869.8
Rate Matters (Note 4)		
Commitments and Contingencies (Note 6)		
COMMON SHAREHOLDER'S EQUITY		
Common Stock – No Par Value:		
Authorized – 2,500,000 Shares		
Outstanding – 1,400,000 Shares	56 6	56 6
Paid-in Capital	980 9	980 9
Retained Earnings	1,518.5	1,329 1
Accumulated Other Comprehensive Income (Loss)	(11 6)	(13 8)
TOTAL COMMON SHAREHOLDER'S EQUITY	2,544 4	2,352 8
TOTAL LIABILITIES AND COMMON SHAREHOLDER'S EQUITY	$ 11,237.4	$ 10,222.6

See Notes to Financial Statements of Registrants beginning on page 156

INDIANA MICHIGAN POWER COMPANY AND SUBSIDIARIES
CONSOLIDATED STATEMENTS OF CASH FLOWS
For the Years Ended December 31, 2019, 2018 and 2017
(in millions)

	Years Ended December 31, 2019	2018	2017
OPERATING ACTIVITIES			
Net Income	$ 269.4	$ 261.3	$ 186.7
Adjustments to Reconcile Net Income to Net Cash Flows from Operating Activities:			
Depreciation and Amortization	350.6	293.1	210.9
Rockport Plant, Unit 2 Operating Lease Amortization	69.2	—	—
Deferred Income Taxes	(52.7)	(42.9)	200.7
Amortization (Deferral) of Incremental Nuclear Refueling Outage Expenses, Net	(26.4)	29.2	8.5
Allowance for Equity Funds Used During Construction	(19.4)	(11.9)	(11.1)
Mark-to-Market of Risk Management Contracts	(0.6)	(4.1)	(2.3)
Amortization of Nuclear Fuel	89.1	113.8	129.1
Pension Contributions to Qualified Plan Trust	—	—	(13.0)
Deferred Fuel Over/Under-Recovery, Net	(24.3)	39.7	13.7
Change in Other Noncurrent Assets	8.3	(36.5)	(101.1)
Change in Other Noncurrent Liabilities	33.7	72.1	37.4
Changes in Certain Components of Working Capital:			
Accounts Receivable, Net	35.4	4.8	(1.1)
Fuel, Materials and Supplies	(22.4)	(11.2)	(7.5)
Accounts Payable	3.6	(14.1)	17.6
Accrued Taxes, Net	48.3	41.2	(16.6)
Rockport Plant, Unit 2 Operating Lease Payments	(73.9)	—	—
Other Current Assets	11.2	1.5	14.5
Other Current Liabilities	(13.9)	(10.3)	(5.1)
Net Cash Flows from Operating Activities	685.2	725.7	661.3
INVESTING ACTIVITIES			
Construction Expenditures	(585.9)	(568.5)	(648.5)
Change in Advances to Affiliates, Net	(0.5)	(0.3)	0.1
Purchases of Investment Securities	(1,531.0)	(2,064.7)	(2,300.5)
Sales of Investment Securities	1,473.0	2,010.0	2,256.3
Acquisitions of Nuclear Fuel	(92.3)	(46.1)	(108.0)
Other Investing Activities	16.6	14.8	9.7
Net Cash Flows Used for Investing Activities	(720.1)	(654.8)	(790.9)
FINANCING ACTIVITIES			
Issuance of Long-term Debt - Nonaffiliated	123.3	1,168.1	530.1
Change in Advances from Affiliates, Net	113.3	(210.5)	(3.6)
Retirement of Long-term Debt - Nonaffiliated	(117.1)	(884.9)	(260.7)
Principal Payments for Finance Lease Obligations	(5.7)	(8.8)	(12.0)
Dividends Paid on Common Stock	(80.0)	(124.7)	(125.0)
Other Financing Activities	0.7	(9.0)	0.9
Net Cash Flows from (Used for) Financing Activities	34.5	(69.8)	129.7
Net Increase (Decrease) in Cash and Cash Equivalents	(0.4)	1.1	0.1
Cash and Cash Equivalents at Beginning of Period	2.4	1.3	1.2
Cash and Cash Equivalents at End of Period	$ 2.0	$ 2.4	$ 1.3
SUPPLEMENTARY INFORMATION			
Cash Paid for Interest, Net of Capitalized Amounts	$ 111.9	$ 116.9	$ 94.8
Net Cash Paid (Received) for Income Taxes	3.4	32.6	(89.9)

Noncash Acquisitions Under Finance Leases	11 9	5.8	7 1
Construction Expenditures Included in Current Liabilities as of December 31,	86 0	93 0	88 5
Acquisition of Nuclear Fuel Included in Current Liabilities as of December 31,	0 1	4 0	—
Expected Reimbursement for Capital Cost of Spent Nuclear Fuel Dry Cask Storage	0 3	2 2	2 6

See Notes to Financial Statements of Registrants beginning on page 156.

OHIO POWER COMPANY AND SUBSIDIARIES

OHIO POWER COMPANY AND SUBSIDIARIES
MANAGEMENT'S NARRATIVE DISCUSSION AND ANALYSIS OF RESULTS OF OPERATIONS

COMPANY OVERVIEW

As a public utility, OPCo engages in the transmission and distribution of power to 1,494,000 retail customers in the northwestern, central, eastern and southern sections of Ohio. Effective January 2014, OPCo purchases power from both affiliated and nonaffiliated entities, subject to auction requirements and PUCO approval, to meet the energy and capacity needs of its remaining SSO customers. OPCo consolidates Ohio Phase-in-Recovery Funding LLC, its wholly-owned subsidiary. The Ohio Phase-in-Recovery Funding LLC securitization bonds matured in July 2019.

AEPSC conducts gasoline, diesel fuel, energy procurement and risk management activities on OPCo's behalf.

To minimize the credit requirements and operating constraints when operating within PJM, participating AEP companies, including OPCo, agreed to a netting of certain payment obligations incurred by the participating AEP companies against certain balances due to such AEP companies and to hold PJM harmless from actions that any one or more AEP companies may take with respect to PJM.

RESULTS OF OPERATIONS

KWh Sales/Degree Days

Summary of KWh Energy Sales

	Years Ended December 31,		
	2019	**2018**	**2017**
	(in millions of KWhs)		
Retail:			
Residential	14,411	14,940	13,539
Commercial	14,599	14,655	14,342
Industrial	14,407	14,857	14,709
Miscellaneous	114	115	119
Total Retail (a)(b)	43,531	44,567	42,709
Wholesale (c)	2,335	2,441	2,387
Total KWhs	45,866	47,008	45,096

(a) 2018 and 2017 KWhs have been revised to reflect the reclassification of certain customer accounts between Retail classes. This reclassification did not impact previously reported Total Retail KWhs. Management concluded that these prior period disclosure only errors were immaterial individually and in the aggregate.
(b) Represents energy delivered to distribution customers.
(c) Primarily Ohio's contractually obligated purchases of OVEC power sold into PJM.

Heating degree days and cooling degree days are metrics commonly used in the utility industry as a measure of the impact of weather on revenues.

Summary of Heating and Cooling Degree Days

	Years Ended December 31,		
	2019	**2018**	**2017**
	(in degree days)		
Actual – Heating (a)	3,071	3,357	2,709
Normal – Heating (b)	3,208	3,215	3,225
Actual – Cooling (c)	1,224	1,402	1,002
Normal – Cooling (b)	992	980	974

(a) Heating degree days are calculated on a 55 degree temperature base.
(b) Normal Heating/Cooling represents the thirty-year average of degree days.
(c) Cooling degree days are calculated on a 65 degree temperature base.

2019 Compared to 2018

Reconciliation of Year Ended December 31, 2018 to Year Ended December 31, 2019
Net Income
(in millions)

Year Ended December 31, 2018	$	325.5
Changes in Gross Margin:		
Retail Margins		(36.8)
Margins from Off-system Sales		(30.5)
Transmission Revenues		9.8
Other Revenues		6.9
Total Change in Gross Margin		(50.6)
Changes in Expenses and Other:		
Other Operation and Maintenance		34.6
Depreciation and Amortization		18.8
Taxes Other Than Income Taxes		(21.4)
Interest Income		(0.2)
Carrying Costs Income		(0.7)
Allowance for Equity Funds Used During Construction		8.4
Non-Service Cost Components of Net Periodic Benefit Cost		(0.9)
Interest Expense		(5.5)
Total Change in Expenses and Other		33.1
Income Tax Expense		(10.9)
Year Ended December 31, 2019	$	297.1

The major components of the decrease in Gross Margin, defined as revenues less the related direct cost of purchased electricity and amortization of generation deferrals were as follows:

- **Retail Margins** decreased $37 million primarily due to the following:
  - A $103 million net decrease in Basic Transmission Cost Rider revenues and recoverable PJM expenses. This decrease was partially offset in Other Operation and Maintenance expenses below.
  - A $25 million decrease in Deferred Asset Phase-In-Recovery Rider revenues which ended in the second quarter of 2019. This decrease was offset in Depreciation and Amortization expenses below.
  - A $22 million decrease in revenues associated with a vegetation management rider. This decrease was offset in Other Operation and Maintenance expenses below.
  - A $21 million net decrease in margin for the Phase-In-Recovery Rider including associated amortizations which ended in the first quarter of 2019.
  - A $21 million net decrease in margin for the Rate Stability Rider including associated amortizations which ended in the third quarter of 2019.
  - A $15 million decrease in usage primarily in the residential and commercial classes.

  These decreases were partially offset by:
  - A $58 million increase due to a reversal of a regulatory provision.
  - A $41 million increase in revenues associated with smart grid riders. This increase was partially offset in other expense items below.
  - A $33 million net increase due to 2018 adjustments to the distribution decoupling under-recovery balance as a result of the 2018 Ohio Tax Reform settlement and changes in tax riders. This increase was partially offset in Income Tax Expense below.
  - A $30 million increase due to the recovery of higher current year losses from a power contract with OVEC. This increase was offset in Margins from Off-system Sales below.
  - An $11 million increase in Energy Efficiency/Peak Demand Reduction rider revenues. This increase was offset in Other Operation and Maintenance expenses below.

- **Margins from Off-system Sales** decreased $31 million primarily due to higher current year losses from a power contract with OVEC as a result of the OVEC PPA rider. This decrease was offset in Retail Margins above.
- **Transmission Revenues** increased $10 million primarily due to 2018 provisions for refunds, partially offset by the annual PJM Transmission formula rate true-up.
- **Other Revenues** increased $7 million primarily due to distribution connection fees and pole attachment revenues.

Expenses and Other and Income Tax Expense changed between years as follows:

- **Other Operation and Maintenance** expenses decreased $35 million primarily due to the following:
  - A $107 million decrease in recoverable PJM expenses. This decrease was offset in Gross Margin above.
  - An $11 million decrease in recoverable distribution expenses related to vegetation management. This decrease was partially offset in Retail Margins above.

  These decreases were partially offset by:
  - A $68 million increase in PJM expenses primarily related to the annual formula rate true-up.
  - An $11 million increase in Energy Efficiency/Peak Demand Reduction expenses. This increase was offset in Retail Margins above.
  - A $5 million increase due to a charitable contribution to the AEP Foundation.
- **Depreciation and Amortization** expenses decreased $19 million primarily due to the following:
  - A $26 million decrease in recoverable DIR depreciation expense. This decrease was partially offset in Retail Margins above.
  - A $23 million decrease in amortizations associated with the Deferred Asset Phase-In-Recovery Rider which ended in the second quarter of 2019. This decrease was offset in Retail Margins above.

  These decreases were partially offset by:
  - A $21 million increase in depreciation expense due to an increase in the depreciable base of transmission and distribution assets.
  - An $11 million increase due to lower deferred equity amortizations associated with the Deferred Asset Phase-In-Recovery Rider which ended in the second quarter of 2019.
- **Taxes Other Than Income Taxes** increased $21 million primarily due to an increase in property taxes driven by additional investments in transmission and distribution assets and higher tax rates.
- **Allowance for Equity Funds Used During Construction** increased $8 million primarily due to adjustments that resulted from 2019 FERC audit findings.
- **Interest Expense** increased $6 million primarily due to higher long-term debt balances.
- **Income Tax Expense** increased $11 million primarily due to decreased amortization of Excess ADIT not subject to normalization requirements. This increase was partially offset in Retail Margins above.

REPORT OF INDEPENDENT REGISTERED PUBLIC ACCOUNTING FIRM

To the Board of Directors and Shareholder of
Ohio Power Company

Opinion on the Financial Statements

We have audited the accompanying consolidated balance sheets of Ohio Power Company and its subsidiaries (the "Company") as of December 31, 2019 and 2018, and the related consolidated statements of income, of comprehensive income (loss), of changes in common shareholder's equity and of cash flows for each of the three years in the period ended December 31, 2019, including the related notes (collectively referred to as the "consolidated financial statements"). In our opinion, the consolidated financial statements present fairly, in all material respects, the financial position of the Company as of December 31, 2019 and 2018, and the results of its operations and its cash flows for each of the three years in the period ended December 31, 2019 in conformity with accounting principles generally accepted in the United States of America.

Change in Accounting Principle

As discussed in Note 13 to the consolidated financial statements, the Company changed the manner in which it accounts for leases in 2019.

Basis for Opinion

These consolidated financial statements are the responsibility of the Company's management. Our responsibility is to express an opinion on the Company's consolidated financial statements based on our audits. We are a public accounting firm registered with the Public Company Accounting Oversight Board (United States) (PCAOB) and are required to be independent with respect to the Company in accordance with the U.S. federal securities laws and the applicable rules and regulations of the Securities and Exchange Commission and the PCAOB.

We conducted our audits of these consolidated financial statements in accordance with the standards of the PCAOB. Those standards require that we plan and perform the audit to obtain reasonable assurance about whether the consolidated financial statements are free of material misstatement, whether due to error or fraud. The Company is not required to have, nor were we engaged to perform, an audit of its internal control over financial reporting. As part of our audits we are required to obtain an understanding of internal control over financial reporting but not for the purpose of expressing an opinion on the effectiveness of the Company's internal control over financial reporting. Accordingly, we express no such opinion.

Our audits included performing procedures to assess the risks of material misstatement of the consolidated financial statements, whether due to error or fraud, and performing procedures that respond to those risks. Such procedures included examining, on a test basis, evidence regarding the amounts and disclosures in the consolidated financial statements. Our audits also included evaluating the accounting principles used and significant estimates made by management, as well as evaluating the overall presentation of the consolidated financial statements. We believe that our audits provide a reasonable basis for our opinion.

/s/ PricewaterhouseCoopers LLP

Columbus, Ohio
February 20, 2020

We have served as the Company's auditor since 2017.

MANAGEMENT'S REPORT ON INTERNAL CONTROL OVER FINANCIAL REPORTING

The management of Ohio Power Company and Subsidiaries (OPCo) is responsible for establishing and maintaining adequate internal control over financial reporting as such term is defined in Rule 13a-15(f) and 15d-15(f) under the Securities Exchange Act of 1934, as amended. OPCo's internal control is a process designed to provide reasonable assurance regarding the reliability of financial reporting and the preparation of financial statements for external purposes in accordance with generally accepted accounting principles.

Because of its inherent limitations, internal control over financial reporting may not prevent or detect misstatements. Also, projections of any evaluation of effectiveness to future periods are subject to the risk that controls may become inadequate because of changes in conditions, or that the degree of compliance with the policies or procedures may deteriorate.

Management assessed the effectiveness of OPCo's internal control over financial reporting as of December 31, 2019. In making this assessment, management used the criteria set forth by the Committee of Sponsoring Organizations of the Treadway Commission (COSO) in Internal Control – Integrated Framework (2013). Based on management's assessment, management concluded OPCo's internal control over financial reporting was effective as of December 31, 2019.

This annual report does not include an audit report from PricewaterhouseCoopers LLP, OPCo's registered public accounting firm regarding internal control over financial reporting pursuant to the Securities and Exchange Commission rules that permit OPCo to provide only management's report in this annual report.

OHIO POWER COMPANY AND SUBSIDIARIES
CONSOLIDATED STATEMENTS OF INCOME
For the Years Ended December 31, 2019, 2018 and 2017
(in millions)

	Years Ended December 31,		
	2019	2018	2017
REVENUES			
Electricity, Transmission and Distribution	$ 2,759.5	$ 3,033.8	$ 2,853 5
Sales to AEP Affiliates	27 3	21 0	24 4
Other Revenues	10 8	8 6	6.0
TOTAL REVENUES	2,797 6	3,063 4	2,883 9
EXPENSES			
Purchased Electricity for Resale	607.3	684.6	705.9
Purchased Electricity from AEP Affiliates	156 0	135 3	108 5
Amortization of Generation Deferrals	65 3	223.9	229.2
Other Operation	742 6	771 3	516 0
Maintenance	150 1	156 0	141.2
Depreciation and Amortization	240 9	259 7	225 9
Taxes Other Than Income Taxes	434 2	412.8	391 5
TOTAL EXPENSES	2,396 4	2,643 6	2,318 2
OPERATING INCOME	401 2	419 8	565.7
Other Income (Expense):			
Interest Income	3.2	3 4	4.9
Carrying Costs Income	1 0	1.7	3.6
Allowance for Equity Funds Used During Construction	18.2	9 8	6 4
Non-Service Cost Components of Net Periodic Benefit Cost	14 6	15 5	4.5
Interest Expense	(106 2)	(100 7)	(101 9)
INCOME BEFORE INCOME TAX EXPENSE	332 0	349 5	483.2
Income Tax Expense	34.9	24 0	159 3
NET INCOME	$ 297 1	$ 325 5	$ 323 9

The common stock of OPCo is wholly-owned by Parent

See Notes to Financial Statements of Registrants beginning on page 156.

OHIO POWER COMPANY AND SUBSIDIARIES
CONSOLIDATED STATEMENTS OF COMPREHENSIVE INCOME (LOSS)
For the Years Ended December 31, 2019, 2018 and 2017
(in millions)

	Years Ended December 31,		
	2019	**2018**	**2017**
Net Income	$ 297 1	$ 325.5	$ 323 9
OTHER COMPREHENSIVE LOSS, NET OF TAXES			
Cash Flow Hedges, Net of Tax of $(0.3), $(0 4) and $(0 6) in 2019, 2018 and 2017, Respectively	(1.0)	(1 3)	(1 1)
TOTAL COMPREHENSIVE INCOME	$ 296 1	$ 324 2	$ 322 8

See Notes to Financial Statements of Registrants beginning on page 156

OHIO POWER COMPANY AND SUBSIDIARIES
CONSOLIDATED STATEMENTS OF CHANGES IN COMMON SHAREHOLDER'S EQUITY
For the Years Ended December 31, 2019, 2018 and 2017
(in millions)

	Common Stock	Paid-in Capital	Retained Earnings	Accumulated Other Comprehensive Income (Loss)	Total
TOTAL COMMON SHAREHOLDER'S EQUITY – DECEMBER 31, 2016	$ 321.2	$ 838 8	$ 954 5	$ 3.0	$ 2,117.5
Common Stock Dividends			(130 0)		(130 0)
Net Income			323 9		323 9
Other Comprehensive Loss				(1 1)	(1.1)
TOTAL COMMON SHAREHOLDER'S EQUITY – DECEMBER 31, 2017	321 2	838 8	1,148.4	1 9	2,310 3
Common Stock Dividends			(337 5)		(337 5)
ASU 2018-02 Adoption				0.4	0 4
Net Income			325 5		325 5
Other Comprehensive Loss				(1.3)	(1 3)
TOTAL COMMON SHAREHOLDER'S EQUITY – DECEMBER 31, 2018	321 2	838 8	1,136 4	1.0	2,297 4
Common Stock Dividends			(85 0)		(85.0)
Net Income			297 1		297 1
Other Comprehensive Loss				(1.0)	(1 0)
TOTAL COMMON SHAREHOLDER'S EQUITY – DECEMBER 31, 2019	$ 321 2	$ 838 8	$ 1,348 5	$ —	$ 2,508 5

See Notes to Financial Statements of Registrants beginning on page 156.

OHIO POWER COMPANY AND SUBSIDIARIES
CONSOLIDATED BALANCE SHEETS
ASSETS
December 31, 2019 and 2018
(in millions)

	December 31, 2019	December 31, 2018
CURRENT ASSETS		
Cash and Cash Equivalents	$ 3 7	$ 4 9
Restricted Cash for Securitized Funding	—	27 6
Accounts Receivable.		
Customers	53 0	111 1
Affiliated Companies	59 3	70.8
Accrued Unbilled Revenues	20 3	21 4
Miscellaneous	0.5	0 3
Allowance for Uncollectible Accounts	(0 7)	(1 0)
Total Accounts Receivable	132.4	202.6
Materials and Supplies	52 3	42.9
Renewable Energy Credits	30 9	25.9
Prepayments and Other Current Assets	19 2	15 7
TOTAL CURRENT ASSETS	238 5	319 6
PROPERTY, PLANT AND EQUIPMENT		
Electric		
Transmission	2,686 3	2,544.3
Distribution	5,323 5	4,942.3
Other Property, Plant and Equipment	765 8	574.8
Construction Work in Progress	394 4	432.1
Total Property, Plant and Equipment	9,170 0	8,493.5
Accumulated Depreciation and Amortization	2,263 0	2,218.6
TOTAL PROPERTY, PLANT AND EQUIPMENT – NET	6,907 0	6,274.9
OTHER NONCURRENT ASSETS		
Regulatory Assets	351 8	387 5
Securitized Assets	—	12.9
Deferred Charges and Other Noncurrent Assets	546 3	441 0
TOTAL OTHER NONCURRENT ASSETS	898 1	841.4
TOTAL ASSETS	$ 8,043.6	$ 7,435 9

See Notes to Financial Statements of Registrants beginning on page 156.

OHIO POWER COMPANY AND SUBSIDIARIES
CONSOLIDATED BALANCE SHEETS
LIABILITIES AND COMMON SHAREHOLDER'S EQUITY
December 31, 2019 and 2018
(dollars in millions)

	December 31, 2019	December 31, 2018
CURRENT LIABILITIES		
Advances from Affiliates	$ 131.0	$ 114.1
Accounts Payable		
General	233.7	211.9
Affiliated Companies	103.6	102.9
Long-term Debt Due Within One Year – Nonaffiliated (December 31, 2019 and 2018 Amounts Include $0 and $47.8, Respectively, Related to Ohio Phase-in-Recovery Funding)	0.1	47.9
Risk Management Liabilities	7.3	5.8
Customer Deposits	70.6	113.1
Accrued Taxes	587.9	537.8
Obligations Under Operating Leases	12.5	—
Other Current Liabilities	151.2	214.2
TOTAL CURRENT LIABILITIES	1,297.9	1,347.7
NONCURRENT LIABILITIES		
Long-term Debt – Nonaffiliated	2,081.9	1,668.7
Long-term Risk Management Liabilities	96.3	93.8
Deferred Income Taxes	849.4	763.3
Regulatory Liabilities and Deferred Investment Tax Credits	1,090.9	1,221.2
Obligations Under Operating Leases	76.0	—
Deferred Credits and Other Noncurrent Liabilities	42.7	43.8
TOTAL NONCURRENT LIABILITIES	4,237.2	3,790.8
TOTAL LIABILITIES	5,535.1	5,138.5
Rate Matters (Note 4)		
Commitments and Contingencies (Note 6)		
COMMON SHAREHOLDER'S EQUITY		
Common Stock – No Par Value		
Authorized – 40,000,000 Shares		
Outstanding – 27,952,473 Shares	321.2	321.2
Paid-in Capital	838.8	838.8
Retained Earnings	1,348.5	1,136.4
Accumulated Other Comprehensive Income (Loss)	—	1.0
TOTAL COMMON SHAREHOLDER'S EQUITY	2,508.5	2,297.4
TOTAL LIABILITIES AND COMMON SHAREHOLDER'S EQUITY	$ 8,043.6	$ 7,435.9

See Notes to Financial Statements of Registrants beginning on page 156

OHIO POWER COMPANY AND SUBSIDIARIES
CONSOLIDATED STATEMENTS OF CASH FLOWS
For the Years Ended December 31, 2019, 2018 and 2017
(in millions)

	Years Ended December 31, 2019	2018	2017
OPERATING ACTIVITIES			
Net Income	$ 297 1	$ 325 5	$ 323 9
Adjustments to Reconcile Net Income to Net Cash Flows from Operating Activities:			
Depreciation and Amortization	240 9	259 7	225 9
Amortization of Generation Deferrals	65 3	223 9	229 2
Deferred Income Taxes	43 8	(36 2)	147 9
Allowance for Equity Funds Used During Construction	(18 2)	(9 8)	(6 4)
Mark-to-Market of Risk Management Contracts	4 0	(32 2)	13 0
Pension Contributions to Qualified Plan Trust	—	—	(8 2)
Property Taxes	(33 7)	(12 5)	(17 9)
Refund of Global Settlement	(16 5)	(5 5)	(98 2)
Reversal of Regulatory Provision	(56 2)	—	—
Change in Regulatory Assets	(20 1)	171 5	(70 7)
Change in Other Noncurrent Assets	(35 3)	(11 5)	(54 7)
Change in Other Noncurrent Liabilities	(93 2)	53 8	15 8
Changes in Certain Components of Working Capital:			
Accounts Receivable, Net	75 0	43 1	(30 1)
Materials and Supplies	(16 4)	(11 3)	(11 1)
Accounts Payable	0 4	(13 8)	11 6
Accrued Taxes, Net	38.7	26 8	(9 4)
Other Current Assets	0 8	8 1	(9 2)
Other Current Liabilities	(55 2)	49 1	(29 2)
Net Cash Flows from Operating Activities	421 2	1,028 7	622 2
INVESTING ACTIVITIES			
Construction Expenditures	(799 2)	(725 9)	(567 7)
Change in Advances to Affiliates, Net	—	—	24 2
Other Investing Activities	55 1	18 4	12 6
Net Cash Flows Used for Investing Activities	(744 1)	(707 5)	(530 9)
FINANCING ACTIVITIES			
Issuance of Long-term Debt – Nonaffiliated	444 3	392 8	—
Change in Advances from Affiliates, Net	16 9	26 3	87 8
Retirement of Long-term Debt – Nonaffiliated	(80 3)	(397 1)	(46 4)
Principal Payments for Finance Lease Obligations	(3 5)	(3 8)	(4 1)
Dividends Paid on Common Stock	(85 0)	(337 5)	(130 0)
Other Financing Activities	1 7	0 9	0 8
Net Cash Flows from (Used for) Financing Activities	294 1	(318 4)	(91 9)
Net Increase (Decrease) in Cash, Cash Equivalents and Restricted Cash for Securitized Funding	(28 8)	2 8	(0 6)
Cash, Cash Equivalents and Restricted Cash for Securitized Funding at Beginning of Period	32 5	29 7	30 3
Cash, Cash Equivalents and Restricted Cash for Securitized Funding at End of Period	$ 3 7	$ 32 5	$ 29 7
SUPPLEMENTARY INFORMATION			
Cash Paid for Interest, Net of Capitalized Amounts	$ 100 6	$ 97 1	$ 100 0
Net Cash Paid for Income Taxes	7 3	51 3	48 5
Noncash Acquisitions Under Finance Leases	11 3	4 4	4 5
Construction Expenditures Included in Current Liabilities as of December 31,	125 9	98 2	87 8

See Notes to Financial Statements of Registrants beginning on page 156

PUBLIC SERVICE COMPANY OF OKLAHOMA

PUBLIC SERVICE COMPANY OF OKLAHOMA
MANAGEMENT'S NARRATIVE DISCUSSION AND ANALYSIS OF RESULTS OF OPERATIONS

COMPANY OVERVIEW

As a public utility, PSO engages in the generation and purchase of electric power, and the subsequent sale, transmission and distribution of that power to approximately 559,000 retail customers in its service territory in eastern and southwestern Oklahoma. PSO sells electric power at wholesale to other utilities, municipalities and electric cooperatives. PSO shares off-system sales margins with its customers.

AEPSC conducts power, coal, natural gas, interest rate and, to a lesser extent, heating oil, gasoline and other risk management activities on PSO's behalf. PSO shares in the revenues and expenses associated with these risk management activities, as described in the preceding paragraph, with SWEPCo. Power and natural gas risk management activities are allocated based on the Operating Agreement. Risk management activities primarily include power and natural gas physical transactions, financially-settled swaps and exchange-traded futures. AEPSC settles the majority of the physical forward contracts by entering into offsetting contracts.

Under the SIA, AEPSC allocates physical and financial revenues and expenses from transactions with neighboring utilities, power marketers and other power and natural gas risk management activities based upon the location of such activity, with margins resulting from trading and marketing activities originating in PJM generally accruing to the benefit of APCo, I&M, KPCo and WPCo and trading and marketing activities originating in SPP generally accruing to the benefit of PSO and SWEPCo. Margins resulting from other transactions are allocated among APCo, I&M, KPCo, PSO, SWEPCo and WPCo based upon the common shareholder's equity of these companies.

PSO is jointly and severally liable for activity conducted by AEPSC on the behalf of PSO and SWEPCo related to power purchase and sale activity.

RESULTS OF OPERATIONS

KWh Sales/Degree Days

Summary of KWh Energy Sales

	Years Ended December 31,		
	2019	2018	2017
	(in millions of KWhs)		
Retail:			
Residential	6,273	6,452	5,943
Commercial	4,958	5,005	4,959
Industrial	6,156	6,120	5,882
Miscellaneous	1,246	1,263	1,242
Total Retail (a)	18,633	18,840	18,026
Wholesale	714	758	355
Total KWhs	19,347	19,598	18,381

(a) 2018 and 2017 KWhs have been revised to reflect the reclassification of certain customer accounts between Retail classes. This reclassification did not impact previously reported Total Retail KWhs. Management concluded that these prior period disclosure only errors were immaterial individually and in the aggregate.

Heating degree days and cooling degree days are metrics commonly used in the utility industry as a measure of the impact of weather on revenues.

Summary of Heating and Cooling Degree Days

	Years Ended December 31,		
	2019	2018	2017
	(in degree days)		
Actual – Heating (a)	1,846	1,886	1,249
Normal – Heating (b)	1,751	1,752	1,776
Actual – Cooling (c)	2,265	2,445	2,131
Normal – Cooling (b)	2,160	2,149	2,147

(a) Heating degree days are calculated on a 55 degree temperature base.
(b) Normal Heating/Cooling represents the thirty-year average of degree days.
(c) Cooling degree days are calculated on a 65 degree temperature base.

2019 Compared to 2018

Reconciliation of Year Ended December 31, 2018 to Year Ended December 31, 2019
Net Income
(in millions)

Year Ended December 31, 2018	$	83.2
Changes in Gross Margin:		
Retail Margins (a)		9.1
Margins from Off-system Sales		0.7
Transmission Revenues		(11.2)
Other Revenues		2.3
Total Change in Gross Margin		0.9
Changes in Expenses and Other:		
Other Operation and Maintenance		61.9
Depreciation and Amortization		(5.5)
Taxes Other Than Income Taxes		(0.5)
Interest Income		1.1
Allowance for Funds Used During Construction		2.3
Non-Service Cost Components of Net Periodic Benefit Cost		(0.3)
Interest Expense		(3.0)
Total Change in Expenses and Other		56.0
Income Tax Expense		(2.5)
Year Ended December 31, 2019	$	137.6

(a) Includes firm wholesale sales to municipals and cooperatives.

The major components of the increase in Gross Margin, defined as revenues less the related direct cost of fuel, including consumption of chemicals and emissions allowances, and purchased electricity were as follows:

- **Retail Margins** increased $9 million primarily due to the following:
  - A $46 million increase due to new base rates implemented in April 2019 and March 2018.
  - A $4 million increase in revenue from rate riders. This increase was partially offset in other expense items below.

These increases were partially offset by:
  - A $17 million decrease in weather-normalized margins.
  - A $13 million decrease in weather-related usage due to a 7% decrease in cooling degree days.
  - A $9 million decrease due to the impact of Tax Reform. This decrease was partially offset in Income Tax Expense below.
- **Transmission Revenues** decreased $11 million primarily due to a decrease in SPP Base Plan Funding Revenues.

Expenses and Other and Income Tax Expense changed between years as follows:

- **Other Operation and Maintenance** expenses decreased $62 million primarily due to the following:
  - A $34 million decrease in transmission expenses primarily due to decreased SPP transmission services.
  - A $22 million decrease in Energy Efficiency program costs due to a change in amortizations of costs approved by the OCC. This decrease was offset in Retail Margins above.
  - A $12 million decrease due to Wind Catcher Project expenses incurred in 2018.

These decreases were partially offset by:
  - A $3 million increase due to a charitable contribution to the AEP Foundation.

- **Depreciation and Amortization** expenses increased $6 million primarily due to higher depreciable base and new rates implemented in March 2018.
- **Income Tax Expense** increased $3 million primarily due to an increase in pretax book income partially offset by an increase in amortization of Excess ADIT. The amortization of Excess ADIT was partially offset in Retail Margins above.

REPORT OF INDEPENDENT REGISTERED PUBLIC ACCOUNTING FIRM

To the Board of Directors and Shareholder of
Public Service Company of Oklahoma

Opinion on the Financial Statements

We have audited the accompanying balance sheets of Public Service Company of Oklahoma (the "Company") as of December 31, 2019 and 2018, and the related statements of income, of comprehensive income (loss), of changes in common shareholder's equity and of cash flows for each of the three years in the period ended December 31, 2019, including the related notes (collectively referred to as the "financial statements"). In our opinion, the financial statements present fairly, in all material respects, the financial position of the Company as of December 31, 2019 and 2018, and the results of its operations and its cash flows for each of the three years in the period ended December 31, 2019 in conformity with accounting principles generally accepted in the United States of America.

Change in Accounting Principle

As discussed in Note 13 to the financial statements, the Company changed the manner in which it accounts for leases in 2019.

Basis for Opinion

These financial statements are the responsibility of the Company's management. Our responsibility is to express an opinion on the Company's financial statements based on our audits. We are a public accounting firm registered with the Public Company Accounting Oversight Board (United States) (PCAOB) and are required to be independent with respect to the Company in accordance with the U.S. federal securities laws and the applicable rules and regulations of the Securities and Exchange Commission and the PCAOB.

We conducted our audits of these financial statements in accordance with the standards of the PCAOB. Those standards require that we plan and perform the audit to obtain reasonable assurance about whether the financial statements are free of material misstatement, whether due to error or fraud. The Company is not required to have, nor were we engaged to perform, an audit of its internal control over financial reporting. As part of our audits we are required to obtain an understanding of internal control over financial reporting but not for the purpose of expressing an opinion on the effectiveness of the Company's internal control over financial reporting. Accordingly, we express no such opinion.

Our audits included performing procedures to assess the risks of material misstatement of the financial statements, whether due to error or fraud, and performing procedures that respond to those risks. Such procedures included examining, on a test basis, evidence regarding the amounts and disclosures in the financial statements. Our audits also included evaluating the accounting principles used and significant estimates made by management, as well as evaluating the overall presentation of the financial statements. We believe that our audits provide a reasonable basis for our opinion.

/s/ PricewaterhouseCoopers LLP

Columbus, Ohio
February 20, 2020

We have served as the Company's auditor since 2017.

MANAGEMENT'S REPORT ON INTERNAL CONTROL OVER FINANCIAL REPORTING

The management of Public Service Company of Oklahoma (PSO) is responsible for establishing and maintaining adequate internal control over financial reporting as such term is defined in Rule 13a-15(f) and 15d-15(f) under the Securities Exchange Act of 1934, as amended. PSO's internal control is a process designed to provide reasonable assurance regarding the reliability of financial reporting and the preparation of financial statements for external purposes in accordance with generally accepted accounting principles.

Because of its inherent limitations, internal control over financial reporting may not prevent or detect misstatements. Also, projections of any evaluation of effectiveness to future periods are subject to the risk that controls may become inadequate because of changes in conditions, or that the degree of compliance with the policies or procedures may deteriorate.

Management assessed the effectiveness of PSO's internal control over financial reporting as of December 31, 2019. In making this assessment, management used the criteria set forth by the Committee of Sponsoring Organizations of the Treadway Commission (COSO) in Internal Control – Integrated Framework (2013). Based on management's assessment, management concluded PSO's internal control over financial reporting was effective as of December 31, 2019.

This annual report does not include an audit report from PricewaterhouseCoopers LLP, PSO's registered public accounting firm regarding internal control over financial reporting pursuant to the Securities and Exchange Commission rules that permit PSO to provide only management's report in this annual report.

PUBLIC SERVICE COMPANY OF OKLAHOMA
STATEMENTS OF INCOME
For the Years Ended December 31, 2019, 2018 and 2017
(in millions)

	Years Ended December 31,		
	2019	**2018**	**2017**
REVENUES			
Electric Generation, Transmission and Distribution	$ 1,469 6	$ 1,537.6	$ 1,417.5
Sales to AEP Affiliates	6 1	5 4	4 3
Other Revenues	6 1	4 3	5 4
TOTAL REVENUES	1,481 8	1,547 3	1,427 2
EXPENSES			
Fuel and Other Consumables Used for Electric Generation	195.1	240 5	134 5
Purchased Electricity for Resale	458 9	479 9	514 9
Other Operation	315 0	372.8	315 1
Maintenance	100 7	104 8	120 3
Depreciation and Amortization	169 5	164 0	130.4
Taxes Other Than Income Taxes	43 3	42 8	40 5
TOTAL EXPENSES	1,282 5	1,404.8	1,255 7
OPERATING INCOME	199 3	142 5	171 5
Other Income (Expense):			
Interest Income	1 2	0 1	0 1
Allowance for Equity Funds Used During Construction	2 7	0.4	0 5
Non-Service Cost Components of Net Periodic Benefit Cost	8.4	8 7	3 4
Interest Expense	(66 5)	(63 5)	(53 4)
INCOME BEFORE INCOME TAX EXPENSE	145 1	88 2	122 1
Income Tax Expense	7 5	5 0	50 1
NET INCOME	$ 137.6	$ 83.2	$ 72.0

The common stock of PSO is wholly-owned by Parent.

See Notes to Financial Statements of Registrants beginning on page 156.

PUBLIC SERVICE COMPANY OF OKLAHOMA
STATEMENTS OF COMPREHENSIVE INCOME (LOSS)
For the Years Ended December 31, 2019, 2018 and 2017
(in millions)

	Years Ended December 31,		
	2019	**2018**	**2017**
Net Income	$ 137 6	$ 83.2	$ 72 0
OTHER COMPREHENSIVE LOSS, NET OF TAXES			
Cash Flow Hedges, Net of Tax of $(0 3), $(0 3) and $(0 4) in 2019, 2018 and 2017, Respectively	(1 0)	(1 0)	(0 8)
TOTAL COMPREHENSIVE INCOME	$ 136 6	$ 82 2	$ 71 2

See Notes to Financial Statements of Registrants beginning on page 156.

PUBLIC SERVICE COMPANY OF OKLAHOMA
STATEMENTS OF CHANGES IN COMMON SHAREHOLDER'S EQUITY
For the Years Ended December 31, 2019, 2018 and 2017
(in millions)

	Common Stock	Paid-in Capital	Retained Earnings	Accumulated Other Comprehensive Income (Loss)	Total
TOTAL COMMON SHAREHOLDER'S EQUITY – DECEMBER 31, 2016	$ 157 2	$ 364 0	$ 689 5	$ 3.4	$ 1,214.1
Common Stock Dividends			(70.0)		(70.0)
Net Income			72 0		72 0
Other Comprehensive Loss				(0.8)	(0.8)
TOTAL COMMON SHAREHOLDER'S EQUITY – DECEMBER 31, 2017	157.2	364 0	691 5	2 6	1,215 3
Common Stock Dividends			(50 0)		(50 0)
ASU 2018-02 Adoption				0 5	0.5
Net Income			83 2		83 2
Other Comprehensive Loss				(1 0)	(1 0)
TOTAL COMMON SHAREHOLDER'S EQUITY – DECEMBER 31, 2018	157 2	364 0	724 7	2 1	1,248 0
Common Stock Dividends			(11 3)		(11 3)
Net Income			137.6		137 6
Other Comprehensive Loss				(1.0)	(1 0)
TOTAL COMMON SHAREHOLDER'S EQUITY – DECEMBER 31, 2019	$ 157 2	$ 364.0	$ 851 0	$ 1 1	$ 1,373.3

See Notes to Financial Statements of Registrants beginning on page 156.

PUBLIC SERVICE COMPANY OF OKLAHOMA
BALANCE SHEETS
ASSETS
December 31, 2019 and 2018
(in millions)

	December 31, 2019	December 31, 2018
CURRENT ASSETS		
Cash and Cash Equivalents	$ 1.5	$ 2 0
Advances to Affiliates	38 8	—
Accounts Receivable·		
Customers	28 9	32 5
Affiliated Companies	20 6	26 2
Miscellaneous	0 6	5 7
Allowance for Uncollectible Accounts	(0.3)	(0 1)
Total Accounts Receivable	49 8	64 3
Fuel	12.2	12 3
Materials and Supplies	46 8	44 8
Risk Management Assets	15.8	10.4
Accrued Tax Benefits	11 3	14 7
Prepayments and Other Current Assets	12.0	9 4
TOTAL CURRENT ASSETS	188 2	157.9
PROPERTY, PLANT AND EQUIPMENT		
Electric		
Generation	1,574 6	1,577 0
Transmission	948 5	892 3
Distribution	2,684 8	2,572 8
Other Property, Plant and Equipment	342.1	303 5
Construction Work in Progress	133.4	94 0
Total Property, Plant and Equipment	5,683 4	5,439.6
Accumulated Depreciation and Amortization	1,580 1	1,472 9
TOTAL PROPERTY, PLANT AND EQUIPMENT – NET	4,103 3	3,966 7
OTHER NONCURRENT ASSETS		
Regulatory Assets	375 2	369 0
Employee Benefits and Pension Assets	43 9	31 7
Operating Lease Assets	36 8	—
Deferred Charges and Other Noncurrent Assets	4.1	7 1
TOTAL OTHER NONCURRENT ASSETS	460 0	407 8
TOTAL ASSETS	$ 4,751 5	$ 4,532 4

See Notes to Financial Statements of Registrants beginning on page 156.

PUBLIC SERVICE COMPANY OF OKLAHOMA
BALANCE SHEETS
LIABILITIES AND COMMON SHAREHOLDER'S EQUITY
December 31, 2019 and 2018

	December 31,	
	2019	2018
	(in millions)	
CURRENT LIABILITIES		
Advances from Affiliates	$ —	$ 105 5
Accounts Payable.		
General	134 3	126.9
Affiliated Companies	59 3	47.1
Long-term Debt Due Within One Year – Nonaffiliated	13 2	375 5
Risk Management Liabilities	—	1.0
Customer Deposits	58 9	58.6
Accrued Taxes	22 9	22 4
Obligations Under Operating Leases	5 8	—
Regulatory Liability for Over-Recovered Fuel Costs	63 9	20.1
Other Current Liabilities	87 5	64 5
TOTAL CURRENT LIABILITIES	445.8	821 6
NONCURRENT LIABILITIES		
Long-term Debt – Nonaffiliated	1,373 0	911.5
Deferred Income Taxes	628.3	607 8
Regulatory Liabilities and Deferred Investment Tax Credits	837 2	864 7
Asset Retirement Obligations	44 5	46 3
Obligations Under Operating Leases	31 0	—
Deferred Credits and Other Noncurrent Liabilities	18 4	32 5
TOTAL NONCURRENT LIABILITIES	2,932.4	2,462 8
TOTAL LIABILITIES	3,378 2	3,284.4
Rate Matters (Note 4)		
Commitments and Contingencies (Note 6)		
COMMON SHAREHOLDER'S EQUITY		
Common Stock – Par Value – $15 Per Share		
Authorized – 11,000,000 Shares		
Issued – 10,482,000 Shares		
Outstanding – 9,013,000 Shares	157 2	157 2
Paid-in Capital	364.0	364 0
Retained Earnings	851 0	724 7
Accumulated Other Comprehensive Income (Loss)	1.1	2.1
TOTAL COMMON SHAREHOLDER'S EQUITY	1,373 3	1,248 0
TOTAL LIABILITIES AND COMMON SHAREHOLDER'S EQUITY	$ 4,751 5	$ 4,532 4

See Notes to Financial Statements of Registrants beginning on page 156

PUBLIC SERVICE COMPANY OF OKLAHOMA
STATEMENTS OF CASH FLOWS
For the Years Ended December 31, 2019, 2018 and 2017
(in millions)

	Years Ended December 31,		
	2019	2018	2017
OPERATING ACTIVITIES			
Net Income	$ 137.6	$ 83.2	$ 72.0
Adjustments to Reconcile Net Income to Net Cash Flows from Operating Activities:			
Depreciation and Amortization	169.5	164.0	130.4
Deferred Income Taxes	(18.2)	(31.1)	124.7
Allowance for Equity Funds Used During Construction	(2.7)	(0.4)	(0.5)
Mark-to-Market of Risk Management Contracts	(6.4)	(3.0)	(5.6)
Pension Contributions to Qualified Plan Trust	—	—	(5.3)
Deferred Fuel Over/Under-Recovery, Net	43.8	57.4	(5.4)
Provision for Refund, Net	(9.1)	3.8	(43.5)
Change in Other Noncurrent Assets	5.7	—	(27.2)
Change in Other Noncurrent Liabilities	1.8	17.6	4.5
Changes in Certain Components of Working Capital:			
Accounts Receivable, Net	15.4	5.1	(10.9)
Fuel, Materials and Supplies	(1.9)	(2.6)	13.0
Accounts Payable	7.0	17.7	(10.7)
Accrued Taxes, Net	3.9	13.2	0.8
Other Current Assets	(0.7)	(0.8)	(2.1)
Other Current Liabilities	4.6	6.4	3.9
Net Cash Flows from Operating Activities	350.3	330.5	238.1
INVESTING ACTIVITIES			
Construction Expenditures	(291.9)	(240.2)	(266.1)
Change in Advances to Affiliates, Net	(38.8)	—	—
Other Investing Activities	2.6	7.2	4.6
Net Cash Flows Used for Investing Activities	(328.1)	(233.0)	(261.5)
FINANCING ACTIVITIES			
Issuance of Long-term Debt – Nonaffiliated	349.5	—	—
Change in Advances from Affiliates, Net	(105.5)	(44.1)	97.6
Retirement of Long-term Debt – Nonaffiliated	(250.5)	(0.5)	(0.5)
Make Whole Premium on Extinguishment of Long-term Debt	(3.0)	—	—
Principal Payments for Finance Lease Obligations	(3.1)	(3.3)	(3.9)
Dividends Paid on Common Stock	(11.3)	(50.0)	(70.0)
Other Financing Activities	1.2	0.8	0.3
Net Cash Flows from (Used for) Financing Activities	(22.7)	(97.1)	23.5
Net Increase (Decrease) in Cash and Cash Equivalents	(0.5)	0.4	0.1
Cash and Cash Equivalents at Beginning of Period	2.0	1.6	1.5
Cash and Cash Equivalents at End of Period	$ 1.5	$ 2.0	$ 1.6
SUPPLEMENTARY INFORMATION			
Cash Paid for Interest, Net of Capitalized Amounts	$ 61.1	$ 62.0	$ 61.5
Net Cash Paid (Received) for Income Taxes	22.4	17.9	(72.6)
Noncash Acquisitions Under Finance Leases	5.3	4.3	2.1
Construction Expenditures Included in Current Liabilities as of December 31,	46.0	33.2	23.1

See Notes to Financial Statements of Registrants beginning on page 156.

SOUTHWESTERN ELECTRIC POWER COMPANY CONSOLIDATED

**SOUTHWESTERN ELECTRIC POWER COMPANY CONSOLIDATED
MANAGEMENT'S NARRATIVE DISCUSSION AND ANALYSIS OF RESULTS OF OPERATIONS**

COMPANY OVERVIEW

As a public utility, SWEPCo engages in the generation and purchase of electric power, and the subsequent sale, transmission and distribution of that power to approximately 540,000 retail customers in its service territory in northeastern and the panhandle of Texas, northwestern Louisiana and western Arkansas. SWEPCo consolidates its wholly-owned subsidiary, Southwest Arkansas Utilities Corporation. SWEPCo also consolidates Sabine Mining Company, a variable interest entity. SWEPCo sells electric power at wholesale to other utilities, municipalities and electric cooperatives. SWEPCo shares off-system sales margins with its customers.

AEPSC conducts power, coal, natural gas, interest rate and, to a lesser extent, heating oil, gasoline and other risk management activities on SWEPCo's behalf. SWEPCo shares in the revenues and expenses associated with these risk management activities, as described in the preceding paragraph, with PSO. Power and natural gas risk management activities are allocated based on the Operating Agreement. Risk management activities primarily include power and natural gas physical transactions, financially-settled swaps and exchange-traded futures. AEPSC settles the majority of the physical forward contracts by entering into offsetting contracts.

Under the SIA, AEPSC allocates physical and financial revenues and expenses from transactions with neighboring utilities, power marketers and other power and natural gas risk management activities based upon the location of such activity, with margins resulting from trading and marketing activities originating in PJM generally accruing to the benefit of APCo, I&M, KPCo and WPCo and trading and marketing activities originating in SPP generally accruing to the benefit of PSO and SWEPCo. Margins resulting from other transactions are allocated among APCo, I&M, KPCo, PSO, SWEPCo and WPCo based upon the common shareholder's equity of these companies.

SWEPCo is jointly and severally liable for activity conducted by AEPSC on the behalf of PSO and SWEPCo related to power purchase and sale activity.

RESULTS OF OPERATIONS

KWh Sales/Degree Days

Summary of KWh Energy Sales

	Years Ended December 31, 2019	2018	2017
	(in millions of KWhs)		
Retail:			
Residential	6,303	6,564	5,903
Commercial	5,776	5,911	5,824
Industrial	5,337	5,391	5,339
Miscellaneous	80	79	81
Total Retail (a)	17,496	17,945	17,147
Wholesale	6,791	7,071	8,324
Total KWhs	24,287	25,016	25,471

(a) 2018 and 2017 KWhs have been revised to reflect the reclassification of certain customer accounts between Retail classes. This reclassification did not impact previously reported Total Retail KWhs. Management concluded that these prior period disclosure only errors were immaterial individually and in the aggregate.

Heating degree days and cooling degree days are metrics commonly used in the utility industry as a measure of the impact of weather on revenues.

Summary of Heating and Cooling Degree Days

	Years Ended December 31, 2019	2018	2017
	(in degree days)		
Actual – Heating (a)	1,174	1,308	829
Normal – Heating (b)	1,191	1,195	1,208
Actual – Cooling (c)	2,392	2,560	2,197
Normal – Cooling (b)	2,321	2,311	2,312

(a) Heating degree days are calculated on a 55 degree temperature base.
(b) Normal Heating/Cooling represents the thirty-year average of degree days.
(c) Cooling degree days are calculated on a 65 degree temperature base.

2019 Compared to 2018

**Reconciliation of Year Ended December 31, 2018 to Year Ended December 31, 2019
Earnings Attributable to SWEPCo Common Shareholder
(in millions)**

Year Ended December 31, 2018	$	147.2
Changes in Gross Margin:		
Retail Margins (a)		(6.0)
Margins from Off-system Sales		(1.9)
Transmission Revenues		(35.4)
Other Revenues		(0.6)
Total Change in Gross Margin		(43.9)
Changes in Expenses and Other:		
Other Operation and Maintenance		32.1
Depreciation and Amortization		(9.6)
Taxes Other Than Income Taxes		(0.6)
Interest Income		(2.8)
Allowance for Equity Funds Used During Construction		0.8
Non-Service Cost Components of Net Periodic Benefit Cost		(0.2)
Interest Expense		8.8
Total Change in Expenses and Other		28.5
Income Tax Expense (Benefit)		25.1
Equity Earnings (Loss) of Unconsolidated Subsidiary		0.3
Net Income Attributable to Noncontrolling Interest		1.4
Year Ended December 31, 2019	$	158.6

(a) Includes firm wholesale sales to municipals and cooperatives.

The major components of the decrease in Gross Margin, defined as revenues less the related direct cost of fuel, including consumption of chemicals and emissions allowances, and purchased electricity were as follows:

- **Retail Margins** decreased $6 million primarily due to the following:
  - A $19 million decrease in weather-related usage primarily due to a 7% decrease in cooling degree days and a 10% decrease in heating degree days.
  - A $12 million decrease due to the impact of Tax Reform. This decrease was partially offset in Income Tax Expense (Benefit) below.

  These decreases were partially offset by:
  - A $20 million increase primarily due to rider and base rate revenue increases in Louisiana and Texas. This increase was partially offset in other expense items below.
  - A $6 million increase in weather-normalized margins.
- **Transmission Revenues** decreased $35 million primarily due to the following:
  - A $40 million decrease in the annual SPP formula rate true-up.
  - An $8 million decrease primarily due to a reduction in SPP Base Plan Funding revenues.

  These decreases were partially offset by:
  - A $13 million increase due to a provision for refund recorded in 2018 related to certain transmission assets that management believes should not have been included in the SPP formula rate.

Expenses and Other and Income Tax Expense (Benefit) changed between years as follows:

- **Other Operation and Maintenance** expenses decreased $32 million primarily due to the following:
  - A $28 million decrease due to Wind Catcher Project expenses incurred in 2018.
  - A $20 million decrease in affiliated SPP transmission expenses primarily due to the annual formula rate true-up.

  These decreases were partially offset by:
  - An $11 million increase in storm-related expenses.
  - A $6 million increase due to a charitable contribution to the AEP Foundation.
- **Depreciation and Amortization** expenses increased $10 million primarily due to higher depreciation rates implemented in the third quarter of 2018 and a higher depreciable base.
- **Interest Expense** decreased $9 million primarily due to lower interest rates on outstanding long-term debt.
- **Income Tax Expense (Benefit)** decreased $25 million primarily due to an increase in amortization of Excess ADIT not subject to normalization requirements and a decrease in state tax expense. This decrease was partially offset in Retail Margins above.

REPORT OF INDEPENDENT REGISTERED PUBLIC ACCOUNTING FIRM

To the Board of Directors and Shareholder of
Southwestern Electric Power Company

Opinion on the Financial Statements

We have audited the accompanying consolidated balance sheets of Southwestern Electric Power Company and its subsidiaries (the "Company") as of December 31, 2019 and 2018, and the related consolidated statements of income, of comprehensive income (loss), of changes in equity and of cash flows for each of the three years in the period ended December 31, 2019, including the related notes (collectively referred to as the "consolidated financial statements"). In our opinion, the consolidated financial statements present fairly, in all material respects, the financial position of the Company as of December 31, 2019 and 2018, and the results of its operations and its cash flows for each of the three years in the period ended December 31, 2019 in conformity with accounting principles generally accepted in the United States of America.

Change in Accounting Principle

As discussed in Note 13 to the consolidated financial statements, the Company changed the manner in which it accounts for leases in 2019.

Basis for Opinion

These consolidated financial statements are the responsibility of the Company's management. Our responsibility is to express an opinion on the Company's consolidated financial statements based on our audits. We are a public accounting firm registered with the Public Company Accounting Oversight Board (United States) (PCAOB) and are required to be independent with respect to the Company in accordance with the U.S. federal securities laws and the applicable rules and regulations of the Securities and Exchange Commission and the PCAOB.

We conducted our audits of these consolidated financial statements in accordance with the standards of the PCAOB. Those standards require that we plan and perform the audit to obtain reasonable assurance about whether the consolidated financial statements are free of material misstatement, whether due to error or fraud. The Company is not required to have, nor were we engaged to perform, an audit of its internal control over financial reporting. As part of our audits we are required to obtain an understanding of internal control over financial reporting but not for the purpose of expressing an opinion on the effectiveness of the Company's internal control over financial reporting. Accordingly, we express no such opinion.

Our audits included performing procedures to assess the risks of material misstatement of the consolidated financial statements, whether due to error or fraud, and performing procedures that respond to those risks. Such procedures included examining, on a test basis, evidence regarding the amounts and disclosures in the consolidated financial statements. Our audits also included evaluating the accounting principles used and significant estimates made by management, as well as evaluating the overall presentation of the consolidated financial statements. We believe that our audits provide a reasonable basis for our opinion.

/s/ PricewaterhouseCoopers LLP

Columbus, Ohio
February 20, 2020

We have served as the Company's auditor since 2017.

MANAGEMENT'S REPORT ON INTERNAL CONTROL OVER FINANCIAL REPORTING

The management of Southwestern Electric Power Company Consolidated (SWEPCo) is responsible for establishing and maintaining adequate internal control over financial reporting as such term is defined in Rule 13a-15(f) and 15d-15(f) under the Securities Exchange Act of 1934, as amended. SWEPCo's internal control is a process designed to provide reasonable assurance regarding the reliability of financial reporting and the preparation of financial statements for external purposes in accordance with generally accepted accounting principles.

Because of its inherent limitations, internal control over financial reporting may not prevent or detect misstatements. Also, projections of any evaluation of effectiveness to future periods are subject to the risk that controls may become inadequate because of changes in conditions, or that the degree of compliance with the policies or procedures may deteriorate.

Management assessed the effectiveness of SWEPCo's internal control over financial reporting as of December 31, 2019. In making this assessment, management used the criteria set forth by the Committee of Sponsoring Organizations of the Treadway Commission (COSO) in Internal Control – Integrated Framework (2013). Based on management's assessment, management concluded SWEPCo's internal control over financial reporting was effective as of December 31, 2019.

This annual report does not include an audit report from PricewaterhouseCoopers LLP, SWEPCo's registered public accounting firm regarding internal control over financial reporting pursuant to the Securities and Exchange Commission rules that permit SWEPCo to provide only management's report in this annual report.

SOUTHWESTERN ELECTRIC POWER COMPANY CONSOLIDATED
CONSOLIDATED STATEMENTS OF INCOME
For the Years Ended December 31, 2019, 2018 and 2017
(in millions)

	Years Ended December 31,		
	2019	2018	2017
REVENUES			
Electric Generation, Transmission and Distribution	$ 1,744 6	$ 1,791.9	$ 1,752 1
Sales to AEP Affiliates	36 9	35 1	25 9
Provision for Refund - Affiliated	(32 0)	(6.7)	—
Other Revenues	1 4	1 6	1 9
TOTAL REVENUES	1,750 9	1,821 9	1,779 9
EXPENSES			
Fuel and Other Consumables Used for Electric Generation	472 8	502.3	496 1
Purchased Electricity for Resale	179.5	177 1	168 7
Other Operation	348 0	384 2	318 3
Maintenance	145.6	141.5	143.5
Asset Impairments and Other Related Charges	—	—	33 6
Depreciation and Amortization	249 1	239.5	217.4
Taxes Other Than Income Taxes	100 2	99.6	98 3
TOTAL EXPENSES	1,495.2	1,544.2	1,475.9
OPERATING INCOME	255 7	277.7	304 0
Other Income (Expense):			
Interest Income	2 6	5 4	2 7
Allowance for Equity Funds Used During Construction	6.8	6.0	2 4
Non-Service Cost Component of Net Periodic Benefit Cost	8 5	8 7	3 7
Interest Expense	(119.1)	(127.9)	(123 4)
INCOME BEFORE INCOME TAX EXPENSE (BENEFIT) AND EQUITY EARNINGS (LOSS)	154 5	169 9	189 4
Income Tax Expense (Benefit)	(4 7)	20 4	48 1
Equity Earnings (Loss) of Unconsolidated Subsidiary	3 0	2 7	(3 8)
NET INCOME	162 2	152 2	137 5
Net Income Attributable to Noncontrolling Interest	3.6	5 0	12 8
EARNINGS ATTRIBUTABLE TO SWEPCo COMMON SHAREHOLDER	$ 158 6	$ 147 2	$ 124 7

The common stock of SWEPCo is wholly-owned by Parent.

See Notes to Financial Statements of Registrants beginning on page 156

SOUTHWESTERN ELECTRIC POWER COMPANY CONSOLIDATED
CONSOLIDATED STATEMENTS OF COMPREHENSIVE INCOME (LOSS)
For the Years Ended December 31, 2019, 2018 and 2017
(in millions)

	Years Ended December 31,		
	2019	2018	2017
Net Income	$ 162.2	$ 152 2	$ 137.5
OTHER COMPREHENSIVE INCOME (LOSS), NET OF TAXES			
Cash Flow Hedges, Net of Tax of $0.4, $1 1 and $0 8 in 2019, 2018 and 2017, Respectively	1 5	4 0	1 4
Amortization of Pension and OPEB Deferred Costs, Net of Tax of $(0.3), $(0 4) and $(0 4) in 2019, 2018 and 2017, Respectively	(1 1)	(1 4)	(0 7)
Pension and OPEB Funded Status, Net of Tax of $1, $(0 8) and $2 5 in 2019, 2018 and 2017, Respectively	3 7	(3 1)	4 7
TOTAL OTHER COMPREHENSIVE INCOME (LOSS)	4 1	(0 5)	5 4
TOTAL COMPREHENSIVE INCOME	166 3	151 7	142 9
Total Comprehensive Income Attributable to Noncontrolling Interest	3 6	5 0	12 8
TOTAL COMPREHENSIVE INCOME ATTRIBUTABLE TO SWEPCo COMMON SHAREHOLDER	$ 162 7	$ 146 7	$ 130 1

See Notes to Financial Statements of Registrants beginning on page 156.

SOUTHWESTERN ELECTRIC POWER COMPANY CONSOLIDATED
CONSOLIDATED STATEMENTS OF CHANGES IN EQUITY
For the Years Ended December 31, 2019, 2018 and 2017
(in millions)

	SWEPCo Common Shareholder					
	Common Stock	Paid-in Capital	Retained Earnings	Accumulated Other Comprehensive Income (Loss)	Noncontrolling Interest	Total
TOTAL EQUITY – DECEMBER 31, 2016	$ 135.7	$ 676.6	$ 1,411.9	$ (9.4)	$ 0.4	$ 2,215.2
Common Stock Dividends			(110.0)			(110.0)
Common Stock Dividends – Nonaffiliated					(13.6)	(13.6)
Net Income			124.7		12.8	137.5
Other Comprehensive Income				5.4		5.4
TOTAL EQUITY – DECEMBER 31, 2017	135.7	676.6	1,426.6	(4.0)	(0.4)	2,234.5
Common Stock Dividends			(65.0)			(65.0)
Common Stock Dividends – Nonaffiliated					(4.3)	(4.3)
ASU 2018-02 Adoption			(0.4)	(0.9)		(1.3)
Net Income			147.2		5.0	152.2
Other Comprehensive Loss				(0.5)		(0.5)
TOTAL EQUITY – DECEMBER 31, 2018	135.7	676.6	1,508.4	(5.4)	0.3	2,315.6
Common Stock Dividends			(37.5)			(37.5)
Common Stock Dividends – Nonaffiliated					(3.3)	(3.3)
Net Income			158.6		3.6	162.2
Other Comprehensive Income				4.1		4.1
TOTAL EQUITY – DECEMBER 31, 2019	$ 135.7	$ 676.6	$ 1,629.5	$ (1.3)	$ 0.6	$ 2,441.1

See Notes to Financial Statements of Registrants beginning on page 156

SOUTHWESTERN ELECTRIC POWER COMPANY CONSOLIDATED
CONSOLIDATED BALANCE SHEETS
ASSETS
December 31, 2019 and 2018
(in millions)

	December 31,	
	2019	2018
CURRENT ASSETS		
Cash and Cash Equivalents		
(December 31, 2019 and 2018 Amounts Include $0 and $22, Respectively, Related to Sabine)	$ 1.6	$ 24.5
Advances to Affiliates	2 1	83 4
Accounts Receivable		
Customers	29 0	24.5
Affiliated Companies	34.5	28 8
Miscellaneous	13 5	20.2
Allowance for Uncollectible Accounts	(1.7)	(0.7)
Total Accounts Receivable	75.3	72.8
Fuel		
(December 31, 2019 and 2018 Amounts Include $47 and $13 2, Respectively, Related to Sabine)	140 1	98.0
Materials and Supplies		
(December 31, 2019 and 2018 Amounts Include $23 1 and $22.5, Respectively, Related to Sabine)	94 0	90 0
Risk Management Assets	6 4	4.8
Regulatory Asset for Under-Recovered Fuel Costs	4 9	18.8
Prepayments and Other Current Assets	29 7	22.2
TOTAL CURRENT ASSETS	354 1	414 5
PROPERTY, PLANT AND EQUIPMENT		
Electric:		
Generation	4,691 4	4,672 6
Transmission	2,056.5	1,866.9
Distribution	2,270 7	2,178 6
Other Property, Plant and Equipment		
(December 31, 2019 and 2018 Amounts Include $212 3 and $276 9, Respectively, Related to Sabine)	733 4	762.7
Construction Work in Progress	216.9	199.3
Total Property, Plant and Equipment	9,968.9	9,680 1
Accumulated Depreciation and Amortization		
(December 31, 2019 and 2018 Amounts Include $107 5 and $174.6, Respectively, Related to Sabine)	2,873 7	2,808.3
TOTAL PROPERTY, PLANT AND EQUIPMENT – NET	7,095.2	6,871.8
OTHER NONCURRENT ASSETS		
Regulatory Assets	222 4	230 8
Deferred Charges and Other Noncurrent Assets	160 5	111 2
TOTAL OTHER NONCURRENT ASSETS	382 9	342 0
TOTAL ASSETS	$ 7,832 2	$ 7,628.3

See Notes to Financial Statements of Registrants beginning on page 156.

SOUTHWESTERN ELECTRIC POWER COMPANY CONSOLIDATED
CONSOLIDATED BALANCE SHEETS
LIABILITIES AND EQUITY
December 31, 2019 and 2018

	December 31, 2019	December 31, 2018
	(in millions)	
CURRENT LIABILITIES		
Advances from Affiliates	$ 59.9	$ —
Accounts Payable.		
General	138 0	129 1
Affiliated Companies	53 6	64 2
Short-term Debt – Nonaffiliated	18 3	—
Long-term Debt Due Within One Year – Nonaffiliated	121 2	59 7
Risk Management Liabilities	1 9	0.4
Customer Deposits	65 0	64 5
Accrued Taxes	41 8	42 8
Accrued Interest	34 6	34 7
Obligations Under Operating Leases	6.5	—
Other Current Liabilities	133.9	117 5
TOTAL CURRENT LIABILITIES	674.7	512 9
NONCURRENT LIABILITIES		
Long-term Debt – Nonaffiliated	2,534 4	2,653.7
Long-term Risk Management Liabilities	3.1	2.2
Deferred Income Taxes	940 9	902 8
Regulatory Liabilities and Deferred Investment Tax Credits	892.3	923.0
Asset Retirement Obligations	196 7	191.3
Employee Benefits and Pension Obligations	28 1	24.8
Obligations Under Operating Leases	34.7	—
Deferred Credits and Other Noncurrent Liabilities	86.2	102.0
TOTAL NONCURRENT LIABILITIES	4,716 4	4,799 8
TOTAL LIABILITIES	5,391 1	5,312 7
Rate Matters (Notes 4)		
Commitments and Contingencies (Note 6)		
EQUITY		
Common Stock – Par Value – $18 Per Share		
Authorized - 7,600,000 Shares		
Outstanding – 7,536,640 Shares	135 7	135 7
Paid-in Capital	676 6	676 6
Retained Earnings	1,629 5	1,508 4
Accumulated Other Comprehensive Income (Loss)	(1.3)	(5 4)
TOTAL COMMON SHAREHOLDER'S EQUITY	2,440 5	2,315 3
Noncontrolling Interest	0 6	0 3
TOTAL EQUITY	2,441.1	2,315 6
TOTAL LIABILITIES AND EQUITY	$ 7,832 2	$ 7,628 3

See Notes to Financial Statements of Registrants beginning on page 156

SOUTHWESTERN ELECTRIC POWER COMPANY CONSOLIDATED
CONSOLIDATED STATEMENTS OF CASH FLOWS
For the Years Ended December 31, 2019, 2018 and 2017
(in millions)

	Years Ended December 31, 2019	2018	2017
OPERATING ACTIVITIES			
Net Income	$ 162 2	$ 152.2	$ 137 5
Adjustments to Reconcile Net Income to Net Cash Flows from Operating Activities:			
Depreciation and Amortization	249 1	239.5	217 4
Deferred Income Taxes	(11 0)	1 2	80 5
Asset Impairments and Other Related Charges	—	—	33 6
Allowance for Equity Funds Used During Construction	(6 8)	(6 0)	(2.4)
Mark-to-Market of Risk Management Contracts	0 8	4.0	(5.6)
Pension Contributions to Qualified Plan Trust	—	—	(8 9)
Deferred Fuel Over/Under-Recovery, Net	16.5	(2.4)	(0 8)
Change in Other Noncurrent Assets	6.2	(18 8)	(9 2)
Change in Other Noncurrent Liabilities	2.7	42 8	4.7
Changes in Certain Components of Working Capital:			
Accounts Receivable, Net	—	53 5	(32 9)
Fuel, Materials and Supplies	(46 1)	3 5	(16 0)
Accounts Payable	(28.4)	0 9	10.5
Accrued Taxes, Net	(3.2)	2 3	45 7
Other Current Assets	(8.9)	15 6	5 2
Other Current Liabilities	6 7	16.5	(14 6)
Net Cash Flows from Operating Activities	339.8	504.8	444.7
INVESTING ACTIVITIES			
Construction Expenditures	(412 7)	(451 0)	(404 1)
Change in Advances to Affiliates, Net	81 3	(81 4)	167 8
Proceeds from Sales of Assets	0 2	1 4	12 6
Other Investing Activities	1.0	2 1	3.1
Net Cash Flows Used for Investing Activities	(330 2)	(528 9)	(220 6)
FINANCING ACTIVITIES			
Issuance of Long-term Debt – Nonaffiliated	—	1,065.7	114 6
Change in Short-term Debt – Nonaffiliated	18.3	(22 0)	22 0
Change in Advances from Affiliates, Net	59.9	(118.7)	118 7
Retirement of Long-term Debt – Nonaffiliated	(59 7)	(794 5)	(353 7)
Principal Payments for Finance Lease Obligations	(11.0)	(11 5)	(11 3)
Dividends Paid on Common Stock	(37 5)	(65 0)	(110 0)
Dividends Paid on Common Stock – Nonaffiliated	(3.3)	(4 3)	(13 6)
Other Financing Activities	0 8	(2 7)	0 5
Net Cash Flows from (Used for) Financing Activities	(32 5)	47 0	(232.8)
Net Increase (Decrease) in Cash and Cash Equivalents	(22.9)	22 9	(8 7)
Cash and Cash Equivalents at Beginning of Period	24 5	1 6	10 3
Cash and Cash Equivalents at End of Period	$ 1 6	$ 24 5	$ 1.6
SUPPLEMENTARY INFORMATION			
Cash Paid for Interest, Net of Capitalized Amounts	$ 111.1	$ 125 7	$ 124 4
Net Cash Paid (Received) for Income Taxes	8.6	18 8	(75 3)
Noncash Acquisitions Under Finance Leases	7 4	3 6	3 3
Construction Expenditures Included in Current Liabilities as of December 31,	69.1	42 0	71 2

See Notes to Financial Statements of Registrants beginning on page 156.

INDEX OF NOTES TO FINANCIAL STATEMENTS OF REGISTRANTS

The notes to financial statements are a combined presentation for the Registrants. The following list indicates Registrants to which the notes apply. Specific disclosures within each note apply to all Registrants unless indicated otherwise.

1. ORGANIZATION AND SUMMARY OF SIGNIFICANT ACCOUNTING POLICIES

The disclosures in this note apply to all Registrants unless indicated otherwise.

ORGANIZATION

The Registrants engage in the generation, transmission and distribution of electric power. The Registrant Subsidiaries that conduct most of these activities are regulated by the FERC under the Federal Power Act and the Energy Policy Act of 2005 and maintain accounts in accordance with the FERC and other regulatory guidelines. Most of these companies are subject to further regulation with regard to rates and other matters by state regulatory commissions.

AEP provides competitive electric and gas supply for residential, commercial and industrial customers in deregulated electricity markets and also provides energy management solutions throughout the United States, including energy efficiency services through its independent retail electric supplier.

The Registrants also engage in wholesale electricity, natural gas and other commodity marketing and risk management activities in the United States and provide various energy-related services. In addition, AEP operates competitive wind and solar farms. I&M provides barging services to both affiliated and nonaffiliated companies. SWEPCo, through consolidated and nonconsolidated affiliates, conducts lignite mining operations to fuel certain of its generation facilities.

SUMMARY OF SIGNIFICANT ACCOUNTING POLICIES

Rates and Service Regulation

AEP's public utility subsidiaries' rates are regulated by the FERC and state regulatory commissions in the eleven state operating territories in which they operate. The FERC also regulates the Registrants' affiliated transactions, including AEPSC intercompany service billings which are generally at cost, under the 2005 Public Utility Holding Company Act and the Federal Power Act. The FERC also has jurisdiction over the issuances and acquisitions of securities of the public utility subsidiaries, the acquisition or sale of certain utility assets and mergers with another electric utility or holding company. The state regulatory commissions also regulate certain intercompany transactions under various orders and affiliate statutes. Both the FERC and state regulatory commissions are permitted to review and audit the relevant books and records of companies within a public utility holding company system.

The FERC regulates wholesale power markets and wholesale power transactions. The Registrants' wholesale power transactions are generally market-based. Wholesale power transactions are cost-based regulated when a cost-based contract is negotiated and filed with the FERC or the FERC determines that the Registrants have "market power" in the region where the transaction occurs. Wholesale power supply contracts have been entered into with various municipalities and cooperatives that are FERC-regulated, cost-based contracts. These contracts are generally formula rate mechanisms, which are trued up to actual costs annually.

The state regulatory commissions regulate all of the retail distribution operations and rates of the Registrants' retail public utility subsidiaries on a cost basis. The state regulatory commissions also regulate the retail generation/power supply operations and rates except in Ohio and the ERCOT region of Texas. For generation in Ohio, customers who have not switched to a CRES provider for generation pay market-based auction rates. In addition, all OPCo distribution customers paid for certain legacy generation deferral balances that were fully recovered as of December 31, 2019 and continue to pay for certain legacy deferred generation-related costs through PUCO approved riders. In the ERCOT region of Texas, the generation/supply business is under customer choice and market pricing is conducted by REPs. AEP has no active REPs in ERCOT. AEP's nonregulated subsidiaries enter into short and long-term wholesale transactions to buy or sell capacity, energy and ancillary services in the ERCOT market. In addition, these nonregulated subsidiaries control certain wind and coal-fired generation assets, the power from which is marketed and sold in ERCOT.

The FERC also regulates the Registrants' wholesale transmission operations and rates. Retail transmission rates are based upon the FERC OATT rate when retail rates are unbundled in connection with restructuring. Retail transmission rates are based on formula rates included in the PJM OATT that are cost-based and are unbundled in Ohio for OPCo, in Virginia for APCo and in Michigan for I&M. AEP Texas' retail transmission rates in Texas are unbundled but the retail transmission rates are regulated, on a cost basis, by the PUCT. Bundled retail transmission rates are regulated, on a cost basis, by the state commissions. Transmission rates for AEPTCo's seven wholly-owned transmission subsidiaries within the AEP Transmission Holdco segment are based on formula rates included in the applicable RTO's OATT that are cost-based.

In West Virginia, APCo and WPCo provide retail electric service at bundled rates approved by the WVPSC, with rates set on a combined cost-of-service basis.

In addition, the FERC regulates the SIA, Operating Agreement, Transmission Agreement and Transmission Coordination Agreement, all of which allocate shared system costs and revenues among the utility subsidiaries that are parties to each agreement. The FERC also regulates the PCA. See Note 16 - Related Party Transactions for additional information.

Principles of Consolidation

AEP's consolidated financial statements include its wholly-owned and majority-owned subsidiaries and VIEs of which AEP is the primary beneficiary. The consolidated financial statements for AEP Texas include the Registrant Subsidiary, its wholly-owned subsidiaries, Transition Funding (consolidated VIEs) and Restoration Funding (a consolidated VIE). The consolidated financial statements for APCo include the Registrant Subsidiary, its wholly-owned subsidiaries and Appalachian Consumer Rate Relief Funding (a consolidated VIE). The consolidated financial statements for I&M include the Registrant Subsidiary, its wholly-owned subsidiaries and DCC Fuel (consolidated VIEs). The consolidated financial statements for OPCo include the Registrant Subsidiary and Ohio Phase-in-Recovery Funding (a consolidated VIE). In July 2019, the Ohio Phase-in Recovery Funding securitization bonds matured. The consolidated financial statements for SWEPCo include the Registrant Subsidiary, its wholly-owned subsidiary and Sabine (a consolidated VIE). Intercompany items are eliminated in consolidation.

The equity method of accounting is used for equity investments where the Registrants exercise significant influence but do not hold a controlling financial interest. Such investments are initially recorded at cost in Deferred Charges and Other Noncurrent Assets on the balance sheets. The proportionate share of the investee's equity earnings or losses is included in Equity Earnings of Unconsolidated Subsidiaries on the statements of income.

AEP, AEP Texas, I&M, PSO and SWEPCo have ownership interests in generating units that are jointly-owned. The proportionate share of the operating costs associated with such facilities is included on the income statements and the assets and liabilities are reflected on the balance sheets. See Note 17 - Variable Interest Entities and Equity Method Investments and Note 18 - Property, Plant and Equipment for additional information.

Accounting for the Effects of Cost-Based Regulation

The Registrants' financial statements reflect the actions of regulators that result in the recognition of certain revenues and expenses in different time periods than enterprises that are not rate-regulated. In accordance with accounting guidance for "Regulated Operations," regulatory assets (deferred expenses) and regulatory liabilities (deferred revenue reductions or refunds) are recorded to reflect the economic effects of regulation in the same accounting period by matching expenses with their recovery through regulated revenues and by matching income with its passage to customers in cost-based regulated rates.

Use of Estimates

The preparation of these financial statements in conformity with GAAP requires management to make estimates and assumptions that affect the amounts reported in the financial statements and accompanying notes. These estimates include, but are not limited to, inventory valuation, allowance for doubtful accounts, goodwill, intangible and long-lived asset impairment, unbilled electricity revenue, valuation of long-term energy contracts, the effects of regulation, long-lived asset recovery, storm costs, the effects of contingencies and certain assumptions made in accounting for pension and postretirement benefits. The estimates and assumptions used are based upon management's evaluation of the relevant facts and circumstances as of the date of the financial statements. Actual results could ultimately differ from those estimates.

Cash and Cash Equivalents

Cash and Cash Equivalents include temporary cash investments with original maturities of three months or less.

Restricted Cash (Applies to AEP, AEP Texas, APCo and OPCo)

Restricted Cash primarily includes funds held by trustees for the payment of securitization bonds and contractually restricted deposits held for the future payment of the remaining construction activities at the Santa Rita East wind generation facility.

Reconciliation of Cash, Cash Equivalents and Restricted Cash

The following tables provide a reconciliation of Cash, Cash Equivalents and Restricted Cash reported within the balance sheets that sum to the total of the same amounts shown on the statement of cash flows:

	December 31, 2019			
	AEP	**AEP Texas**	**APCo**	**OPCo**
	(in millions)			
Cash and Cash Equivalents	$ 246 8	$ 3 1	$ 3 3	$ 3.7
Restricted Cash	185 8	154 7	23 5	—
Total Cash, Cash Equivalents and Restricted Cash	$ 432 6	$ 157.8	$ 26.8	$ 3.7

	December 31, 2018			
	AEP	**AEP Texas**	**APCo**	**OPCo**
	(in millions)			
Cash and Cash Equivalents	$ 234.1	$ 3.1	$ 4 2	$ 4.9
Restricted Cash	210 0	156 7	25 6	27 6
Total Cash, Cash Equivalents and Restricted Cash	$ 444 1	$ 159 8	$ 29 8	$ 32 5

Other Temporary Investments (Applies to AEP)

Other Temporary Investments primarily include marketable securities and investments by its protected cell of EIS. These securities have readily determinable fair values and are carried at fair value with changes in fair value recognized in net income. The cost of securities sold is based on the specific identification or weighted-average cost method. See "Fair Value Measurements of Other Temporary Investments" section of Note 11 for additional information.

Inventory

Fossil fuel inventories are carried at average cost with the exception of AGR and AEP's non-regulated ownership share of Oklaunion Power Station, which is carried at the lower of average cost or net realizable value. Materials and supplies inventories are carried at average cost. AEP and SWEPCo reclassified approximately $23 million, as of December 31, 2018, from Fuel to Materials and Supplies related to Sabine.

Accounts Receivable

Customer accounts receivable primarily include receivables from wholesale and retail energy customers, receivables from energy contract counterparties related to risk management activities and customer receivables primarily related to other revenue-generating activities.

Revenue is recognized over time as the performance obligations of delivering energy to customers are satisfied. To the extent that deliveries have occurred but a bill has not been issued, the Registrants accrue and recognize, as Accrued Unbilled Revenues on the balance sheets, an estimate of the revenues for energy delivered since the last billing.

AEP Credit factors accounts receivable on a daily basis, excluding receivables from risk management activities, through purchase agreements with I&M, KGPCo, KPCo, OPCo, PSO, SWEPCo and a portion of APCo. Since APCo does not have regulatory authority to sell accounts receivable in its West Virginia regulatory jurisdiction, only a portion of APCo's accounts receivable are sold to AEP Credit. AEP Credit has a receivables securitization agreement with bank conduits. Under the securitization agreement, AEP Credit receives financing from bank conduits for the interest in the billed and unbilled receivables they acquire from affiliated utility subsidiaries. See "Securitized Accounts Receivable – AEP Credit" section of Note 14 for additional information.

Allowance for Uncollectible Accounts

Generally, AEP Credit records bad debt expense based upon a 12-month rolling average of bad debt write-offs in proportion to gross accounts receivable purchased from participating AEP subsidiaries. For receivables related to APCo's West Virginia operations, the bad debt reserve is calculated based on a rolling two-year average write-off in proportion to gross accounts receivable. For customer accounts receivables relating to risk management activities, accounts receivables are reviewed for bad debt reserves at a specific counterparty level basis. For AEP Texas, bad debt reserves are calculated using the specific identification of receivable balances greater than 120 days delinquent, and for those balances less than 120 days where the collection is doubtful. For miscellaneous accounts receivable, bad debt expense is recorded for all amounts outstanding 180 days or greater at 100%, unless specifically identified. Miscellaneous accounts receivable items open less than 180 days may be reserved using specific identification for bad debt reserves.

Concentrations of Credit Risk and Significant Customers (Applies to Registrant Subsidiaries)

APCo, I&M, OPCo, PSO and SWEPCo do not have any significant customers that comprise 10% or more of their operating revenues. AEP Texas had significant transactions with REPs which on a combined basis account for the following percentages of Total Revenues for the years ended December 31 and Accounts Receivable – Customers as of December 31:

Significant Customers of AEP Texas: Centrica, TXU Energy and Reliant Energy	2019	2018	2017 (a)
Percentage of Total Revenues	48%	45%	35%
Percentage of Accounts Receivable – Customers	43%	35%	31%

(a) TXU Energy did not meet the Total Revenue threshold of 10% in order to be considered a significant customer.

AEPTCo had significant transactions with AEP Subsidiaries which on a combined basis account for the following percentages of Total Revenues for the years ended December 31 and Total Accounts Receivable as of December 31:

Significant Customers of AEPTCo: AEP Subsidiaries	2019	2018	2017
Percentage of Total Revenues	79%	77%	80%
Percentage of Total Accounts Receivable	78%	84%	85%

The Registrant Subsidiaries monitor credit levels and the financial condition of their customers on a continuous basis to minimize credit risk. The regulatory commissions allow recovery in rates for a reasonable level of bad debt costs. Management believes adequate provisions for credit loss have been made in the accompanying Registrant Subsidiary financial statements.

Renewable Energy Credits (Applies to all Registrants except AEP Texas and AEPTCo)

In regulated jurisdictions, the Registrants record renewable energy credits (RECs) at cost. For AEP's competitive generation business, management records RECs at the lower of cost or market. The Registrants follow the inventory model for these RECs. RECs expected to be consumed within one year are reported in Materials and Supplies on the balance sheets. RECs with expected consumption beyond one year are included in Deferred Charges and Other Noncurrent Assets on the balance sheets. The purchases and sales of RECs are reported in the Operating Activities section of the statements of cash flows. RECs are consumed to meet applicable state renewable portfolio standards and are recorded in Fuel and Other Consumables Used for Electric Generation at an average cost on the statements of income. The net margin on sales of RECs affects the determination of deferred fuel and REC costs and the amortization of regulatory assets for certain jurisdictions.

Property, Plant and Equipment

Regulated

Electric utility property, plant and equipment for rate-regulated operations are stated at original cost. Additions, major replacements and betterments are added to the plant accounts. Under the group composite method of depreciation, continuous interim routine replacements of items such as boiler tubes, pumps, motors, etc. result in original cost retirements, less salvage, being charged to accumulated depreciation. The group composite method of depreciation assumes that on average, asset components are retired at the end of their useful lives and thus there is no gain or loss. The equipment in each primary electric plant account is identified as a separate group. The depreciation rates that are established take into account the past history of interim capital replacements and the amount of removal cost incurred and salvage received. These rates and the related lives are subject to periodic review. Removal costs accrued are typically recorded as regulatory liabilities when the revenue received for removal costs accrued exceeds actual removal costs incurred. The asset removal costs liability is relieved as removal costs are incurred. A regulatory asset balance will occur if actual removal costs incurred exceed accumulated removal costs accrued.

The costs of labor, materials and overhead incurred to operate and maintain plant and equipment are included in operating expenses.

Nuclear fuel, including nuclear fuel in the fabrication phase, is included in Other Property, Plant and Equipment on the balance sheets.

Long-lived assets are required to be tested for impairment when it is determined that the carrying value of the assets may no longer be recoverable or when the assets meet the held-for-sale criteria under the accounting guidance for "Impairment or Disposal of Long-Lived Assets." When it becomes probable that an asset in-service or an asset under construction will be abandoned and regulatory cost recovery has been disallowed or is not probable, the cost of that asset shall be removed from plant-in-service or CWIP and charged to expense. The fair value of an asset is the amount at which that asset could be bought or sold in a current transaction between willing parties, as opposed to a forced or liquidation sale. Quoted market prices in active markets are the best evidence of fair value and are used as the basis for the measurement, if available. In the absence of quoted prices for identical or similar assets in active markets, fair value is estimated using various internal and external valuation methods including cash flow analysis and appraisals.

Nonregulated

Nonregulated operations generally follow the policies of rate-regulated operations listed above but with the following exceptions. Property, plant and equipment of nonregulated operations are stated at original cost (or as adjusted for any applicable impairments) plus the original cost of property acquired or constructed since the acquisition, less disposals. Normal and routine retirements from the plant accounts, net of salvage, are charged to accumulated depreciation for most nonregulated operations under the group composite method of depreciation. A gain or loss would be recorded if the retirement is not considered an interim routine replacement. Removal costs are charged to expense.

Allowance for Funds Used During Construction and Interest Capitalization

For regulated operations, AFUDC represents the estimated cost of borrowed and equity funds used to finance construction projects that is capitalized and recovered through depreciation over the service life of regulated electric utility plant. The Registrants record the equity component of AFUDC in Allowance for Equity Funds Used During Construction and the debt component of AFUDC as a reduction to Interest Expense. For nonregulated operations, including certain generating assets, interest is capitalized during construction in accordance with the accounting guidance for "Capitalization of Interest."

Valuation of Nonderivative Financial Instruments

The book values of Cash and Cash Equivalents, Advances to/from Affiliates, Accounts Receivable, Accounts Payable and Short-term Debt approximate fair value because of the short-term maturity of these instruments.

Fair Value Measurements of Assets and Liabilities (Applies to all Registrants except AEPTCo)

The accounting guidance for "Fair Value Measurements and Disclosures" establishes a fair value hierarchy that prioritizes the inputs used to measure fair value. The hierarchy gives the highest priority to unadjusted quoted prices in active markets for identical assets or liabilities (Level 1 measurement) and the lowest priority to unobservable inputs (Level 3 measurement). Where observable inputs are available for substantially the full term of the asset or liability, the instrument is categorized in Level 2. When quoted market prices are not available, pricing may be completed using comparable securities, dealer values, operating data and general market conditions to determine fair value. Valuation models utilize various inputs such as commodity, interest rate and, to a lesser degree, volatility and credit that include quoted prices for similar assets or liabilities in active markets, quoted prices for identical or similar assets or liabilities in inactive markets, market corroborated inputs (i.e. inputs derived principally from, or correlated to, observable market data) and other observable inputs for the asset or liability.

For commercial activities, exchange-traded derivatives, namely futures contracts, are generally fair valued based on unadjusted quoted prices in active markets and are classified as Level 1. Level 2 inputs primarily consist of OTC broker quotes in moderately active or less active markets, as well as exchange-traded derivatives where there is insufficient market liquidity to warrant inclusion in Level 1. Management verifies price curves using these broker quotes and classifies these fair values within Level 2 when substantially all of the fair value can be corroborated. Management typically obtains multiple broker quotes, which are nonbinding in nature but are based on recent trades in the marketplace. When multiple broker quotes are obtained, the quoted bid and ask prices are averaged. In certain circumstances, a broker quote may be discarded if it is a clear outlier. Management uses a historical correlation analysis between the broker quoted location and the illiquid locations. If the points are highly correlated, these locations are included within Level 2 as well. Certain OTC and bilaterally executed derivative instruments are executed in less active markets with a lower availability of pricing information. Illiquid transactions, complex structured transactions, FTRs and counterparty credit risk may require nonmarket-based inputs. Some of these inputs may be internally developed or extrapolated and utilized to estimate fair value. When such inputs have a significant impact on the measurement of fair value, the instrument is categorized as Level 3. The main driver of contracts being classified as Level 3 is the inability to substantiate energy price curves in the market. A portion of the Level 3 instruments have been economically hedged which limits potential earnings volatility.

AEP utilizes its trustee's external pricing service to estimate the fair value of the underlying investments held in the benefit plan and nuclear trusts. AEP's investment managers review and validate the prices utilized by the trustee to determine fair value. AEP's management performs its own valuation testing to verify the fair values of the securities. AEP receives audit reports of the trustee's operating controls and valuation processes.

Assets in the benefits and nuclear trusts, cash and cash equivalents, other temporary investments and restricted cash for securitized funding are classified using the following methods. Equities are classified as Level 1 holdings if they are actively traded on exchanges. Items classified as Level 1 are investments in money market funds, fixed income and equity mutual funds and equity securities. They are valued based on observable inputs, primarily unadjusted quoted prices in active markets for identical assets. Items classified as Level 2 are primarily investments in individual fixed income securities. Fixed income securities generally do not trade on exchanges and do not have an official closing price but their valuation inputs are based on observable market data. Pricing vendors calculate bond valuations using financial models and matrices. The models use observable inputs including yields on benchmark securities, quotes by securities brokers, rating agency actions, discounts or premiums on securities compared to par prices, changes in yields for U.S. Treasury securities, corporate actions by bond issuers, prepayment schedules and histories, economic events and, for certain securities, adjustments to yields to reflect changes in the rate of inflation. Other securities with model-derived valuation inputs that are observable are also classified as Level 2 investments. Investments with unobservable valuation inputs are classified as Level 3 investments. Investments classified as Other are valued using Net Asset Value as a practical expedient. Items classified as Other are primarily cash equivalent funds, common collective trusts, commingled funds, structured products, private equity, real estate, infrastructure and alternative credit investments. These investments do not have a readily determinable fair value or they contain redemption restrictions which may include the right to suspend redemptions under certain circumstances. Redemption restrictions may also prevent certain investments from being redeemed at the reporting date for the underlying value.

Deferred Fuel Costs (Applies to all Registrants except AEP Texas and AEPTCo)

The cost of fuel and related emission allowances and emission control chemicals/consumables is charged to Fuel and Other Consumables Used for Electric Generation expense when the fuel is burned or the allowance or consumable is utilized. The cost of fuel also includes the cost of nuclear fuel burned which is computed primarily using the units-of-production method. In regulated jurisdictions with an active FAC, fuel cost over-recoveries (the excess of fuel-related revenues over applicable fuel costs incurred) are generally deferred as current regulatory liabilities and under-recoveries (the excess of applicable fuel costs incurred over fuel-related revenues) are generally deferred as current regulatory assets. Fuel cost over-recovery and under-recovery balances are classified as noncurrent when there is a commission-approved plan to delay refunds or recoveries beyond a one year period. These deferrals are amortized when refunded or when billed to customers in later months with the state regulatory commissions' review and approval. The amount of an over-recovery or under-recovery can also be affected by actions of the state regulatory commissions. On a routine basis, state regulatory commissions review and/or audit the Registrants' fuel procurement policies and practices, the fuel cost calculations and FAC deferrals. FAC deferrals are adjusted when costs are no longer probable of recovery or when refunds of fuel reserves are probable.

Changes in fuel costs, including purchased power in Kentucky for KPCo, Indiana and Michigan for I&M, in Arkansas, Louisiana and Texas for SWEPCo, in Oklahoma for PSO, in Virginia and West Virginia for APCo and in West Virginia for WPCo are reflected in rates in a timely manner generally through the FAC. In Ohio, purchased power is reflected in rates through various PUCO approved mechanisms. The FAC generally includes some sharing of off-system sales margins. In West Virginia for APCo and WPCo, all of the non-merchant margins from off-system sales are given to customers through the FAC. A portion of margins from off-system sales are given to customers through the FAC and other rate mechanisms in Oklahoma for PSO, Arkansas, Louisiana and Texas for SWEPCo, Kentucky for KPCo, Virginia for APCo and in Indiana and Michigan for I&M. Beginning in 2020, Arkansas for SWEPCo will start giving all margins from off-system sales to customers through the FAC. Where the FAC or off-system sales sharing mechanism is capped, frozen or non-existent, changes in fuel costs or sharing of off-system sales impact earnings.

Revenue Recognition

Regulatory Accounting

The Registrants' financial statements reflect the actions of regulators that can result in the recognition of revenues and expenses in different time periods than enterprises that are not rate-regulated. Regulatory assets (deferred expenses or alternative revenues recognized in accordance with the guidance for "Regulated Operations") and regulatory liabilities (deferred revenue reductions or refunds) are recorded to reflect the economic effects of regulation in the same accounting period by matching expenses with their recovery through regulated revenues and by matching revenue with its passage to customers in cost-based regulated rates.

When regulatory assets are probable of recovery through regulated rates, assets are recorded on the balance sheets. Regulatory assets are tested for probability of recovery at each balance sheet date or whenever new events occur. Examples of new events include the issuance of a regulatory commission order or passage of new legislation. If it is determined that recovery of a regulatory asset is no longer probable, the regulatory asset is derecognized as a charge against income.

Retail and Wholesale Supply and Delivery of Electricity

The Registrants recognize revenues from customers for retail and wholesale electricity sales and electricity transmission and distribution delivery services. The Registrants recognize such revenues on the statements of income as the performance obligations of delivering energy to customers are satisfied. Recognized revenues include both billed and unbilled amounts. In accordance with the applicable state commission's regulatory treatment, PSO and SWEPCo do not include the fuel portion in unbilled revenue, but rather recognize such revenues when billed to customers.

Wholesale transmission revenue is based on FERC approved formula rate filings made for each calendar year using estimated costs. Revenues initially recognized per the annual rate filing are compared to actual costs, resulting in the subsequent recognition of an over or under recovered amount, with interest, that is refunded or recovered, respectively, in a future year's rates. These annual true-ups meet the definition of alternative revenues in accordance with the accounting guidance for "Regulated Operations", and are recognized by the Registrants in the second quarter of each calendar year following the filing of annual FERC reports. Any portion of the true-ups applicable to an affiliated company is recorded as Accounts Receivable - Affiliated Companies or Accounts Payable - Affiliated Companies on the balance sheets. Any portion of the true-ups applicable to third-parties is recorded as Regulatory Assets or Regulatory Liabilities on the balance sheets. See Note 20 - Revenue from Contracts with Customers for additional information.

Gross versus Net Presentation of Certain Electricity Supply and Delivery Activities

Most of the power produced at the generation plants is sold to PJM or SPP. The Registrants also purchase power from PJM and SPP to supply power to customers. Generally, these power sales and purchases are reported on a net basis as revenues on the statements of income. However, purchases of power in excess of sales to PJM or SPP, on an hourly net basis, used to serve retail load are recorded gross as Purchased Electricity for Resale on the statements of income. With the exception of certain dedicated load bilateral power supply contracts, the transactions of AEP's nonregulated subsidiaries are reported as gross purchases or sales.

Physical energy purchases arising from non-derivative contracts are accounted for on a gross basis in Purchased Electricity for Resale on the statements of income. Energy purchases arising from non-trading derivative contracts are recorded based on the transaction's facts and circumstances. Purchases under non-trading derivatives used to serve accrual based obligations are recorded in Purchased Electricity for Resale on the statements of income. All other non-trading derivative purchases are recorded net in revenues.

In general, the Registrants record expenses when purchased electricity is received and when expenses are incurred, with the exception of certain power purchase contracts that are derivatives and accounted for using MTM accounting where generation/supply rates are not cost-based regulated. In jurisdictions where the generation/supply business is subject to cost-based regulation, the unrealized MTM amounts are deferred as regulatory assets (for losses) and regulatory liabilities (for gains).

Energy Marketing and Risk Management Activities (Applies to all Registrants except AEPTCo)

The Registrants engage in power, capacity and, to a lesser extent, natural gas marketing as major power producers and participants in electricity and natural gas markets. The Registrants also engage in power, capacity, coal, natural gas and, to a lesser extent, heating oil, gasoline and other commodity risk management activities focused on markets where the AEP System owns assets and on adjacent markets. These activities include the purchase-and-sale of energy under forward contracts at fixed and variable prices. These contracts include physical transactions, exchange-traded futures, and to a lesser extent, OTC swaps and options. Certain energy marketing and risk management transactions are with RTOs.

The Registrants recognize revenues from marketing and risk management transactions that are not derivatives as the performance obligation of delivering the commodity is satisfied. Expenses from marketing and risk management transactions that are not derivatives are also recognized upon delivery of the commodity.

The Registrants use MTM accounting for marketing and risk management transactions that are derivatives unless the derivative is designated in a qualifying cash flow hedge relationship or elected normal under the normal purchase normal sale election. The Registrants include realized gains and losses on marketing and risk management transactions in revenues or expense based on the transaction's facts and circumstances. In certain jurisdictions subject to cost-based regulation, unrealized MTM amounts and some realized gains and losses are deferred as regulatory assets (for losses) and regulatory liabilities (for gains). Unrealized MTM gains and losses are included on the balance sheets as Risk Management Assets or Liabilities as appropriate.

Certain qualifying marketing and risk management derivatives transactions are designated as hedges of variability in future cash flows as a result of forecasted transactions (cash flow hedge). In the event the Registrants designate a cash flow hedge, the cash flow hedge's gain or loss is initially recorded as a component of AOCI. When the forecasted transaction is realized and affects net income, the Registrants subsequently reclassify the gain or loss on the hedge from AOCI into revenues or expenses within the same financial statement line item as the forecasted transaction on their statements of income. See "Accounting for Cash Flow Hedging Strategies" section of Note 10 for additional information.

Levelization of Nuclear Refueling Outage Costs (Applies to AEP and I&M)

In accordance with regulatory orders, I&M defers incremental operation and maintenance costs associated with periodic refueling outages at its Cook Plant and amortizes the costs over approximately 18 months, beginning with the month following the start of each unit's refueling outage and lasting until the end of the month in which the same unit's next scheduled refueling outage begins.

Maintenance

The Registrants expense maintenance costs as incurred. If it becomes probable that the Registrants will recover specifically-incurred costs through future rates, a regulatory asset is established to match the expensing of those maintenance costs with their recovery in cost-based regulated revenues. In certain regulated jurisdictions, the Registrants defer costs above the level included in base rates and amortize those deferrals commensurate with recovery through rate riders.

Income Taxes and Investment and Production Tax Credits

The Registrants use the liability method of accounting for income taxes. Under the liability method, deferred income taxes are provided for all temporary differences between the book and tax basis of assets and liabilities which will result in a future tax consequence. Deferred tax assets and liabilities are measured using enacted tax rates expected to apply to taxable income in the years in which the temporary differences are expected to be recovered or settled.

When the flow-through method of accounting for temporary differences is required by a regulator to be reflected in regulated revenues (that is, when deferred taxes are not included in the cost of service for determining regulated rates for electricity), deferred income taxes are recorded and related regulatory assets and liabilities are established to match the regulated revenues and tax expense.

AEP and subsidiaries apply the deferral methodology for the recognition of ITCs. Deferred ITCs are amortized to income tax expense over the life of the asset that generated the credit. Amortization of deferred ITCs begins when the asset is placed into service, except where regulatory commissions reflect ITCs in the rate-making process, then amortization begins when the cash tax benefit is recognized. Alternatively, PTCs reduce income tax expense as they are earned. PTCs are earned when electricity is produced.

The Registrants account for uncertain tax positions in accordance with the accounting guidance for "Income Taxes." The Registrants classify interest expense or income related to uncertain tax positions as interest expense or income as appropriate and classify penalties as Other Operation expense.

Excise Taxes (Applies to all Registrants except AEPTCo)

As agents for some state and local governments, the Registrants collect from customers certain excise taxes levied by those state or local governments on customers. The Registrants do not record these taxes as revenue or expense.

Debt

Gains and losses from the reacquisition of debt used to finance regulated electric utility plants are deferred and amortized over the remaining term of the reacquired debt in accordance with their rate-making treatment unless the debt is refinanced. If the reacquired debt associated with the regulated business is refinanced, the reacquisition costs attributable to the portions of the business that are subject to cost-based regulatory accounting are generally deferred and amortized over the term of the replacement debt consistent with its recovery in rates. Operations not subject to cost-based rate regulation report gains and losses on the reacquisition of debt in Interest Expense on the statements of income upon reacquisition.

Debt discount or premium and debt issuance expenses are deferred and amortized generally utilizing the straight-line method over the term of the related debt. The straight-line method approximates the effective interest method and is consistent with the treatment in rates for regulated operations. The net amortization expense is included in Interest Expense on the statements of income.

Goodwill (Applies to AEP)

When AEP acquires a business, as defined by the accounting guidance for "Business Combinations," management recognizes all acquired assets and liabilities at their fair value. To the extent that consideration exceeds the net fair value of the identified assets and liabilities, goodwill is recognized on the balance sheets. Goodwill is not amortized. Management tests acquired goodwill at the reporting unit level for impairment at least annually at its estimated fair value. Fair value is the amount at which an asset or liability could be bought or sold in a current transaction between willing parties other than in a forced or liquidation sale. Quoted market prices in active markets are the best evidence of fair value and are used as the basis for the measurement, if available. In the absence of quoted prices for identical or similar assets in active markets, management estimates fair value using various internal and external valuation methods.

Pension and OPEB Plans (Applies to all Registrants except AEPTCo)

AEP sponsors a qualified pension plan and two unfunded nonqualified pension plans. Substantially all AEP employees are covered by the qualified plan or both the qualified and a nonqualified pension plan. AEP also sponsors OPEB plans to provide health and life insurance benefits for retired employees. The Registrant Subsidiaries account for their participation in the AEP sponsored pension and OPEB plans using multiple-employer accounting. See Note 8 - Benefit Plans for additional information including significant accounting policies associated with the plans.

Investments Held in Trust for Future Liabilities (Applies to all Registrants except AEPTCo)

AEP has several trust funds with significant investments intended to provide for future payments of pension and OPEB benefits, nuclear decommissioning and SNF disposal. All of the trust funds' investments are diversified and managed in compliance with all laws and regulations. The investment strategy for the trust funds is to use a diversified portfolio of investments to achieve an acceptable rate of return while managing the investment risk of the assets relative to the associated liabilities. To minimize investment risk, the trust funds are broadly diversified among classes of assets, investment strategies and investment managers. Management regularly reviews the actual asset allocations and periodically rebalances the investments to targeted allocations when appropriate. Investment policies and guidelines allow investment managers in approved strategies to use financial derivatives to obtain or manage market exposures and to hedge assets and liabilities. The investments are reported at fair value under the "Fair Value Measurements and Disclosures" accounting guidance.

Benefit Plans

All benefit plan assets are invested in accordance with each plan's investment policy. The investment policy outlines the investment objectives, strategies and target asset allocations by plan.

The investment philosophies for AEP's benefit plans support the allocation of assets to minimize risks and optimize net returns. Strategies used include:

- Maintaining a long-term investment horizon.
- Diversifying assets to help control volatility of returns at acceptable levels.
- Managing fees, transaction costs and tax liabilities to maximize investment earnings.
- Using active management of investments where appropriate risk/return opportunities exist.
- Keeping portfolio structure style-neutral to limit volatility compared to applicable benchmarks.
- Using alternative asset classes such as real estate and private equity to maximize return and provide additional portfolio diversification.

The objective of the investment policy for the pension fund is to maintain the funded status of the plan while providing for growth in the plan assets to offset the growth in the plan liabilities. The current target asset allocations are as follows:

Pension Plan Assets	Target
Equity	30%
Fixed Income	54%
Other Investments	15%
Cash and Cash Equivalents	1%

OPEB Plans Assets	Target
Equity	48%
Fixed Income	50%
Cash and Cash Equivalents	2%

The investment policy for each benefit plan contains various investment limitations. The investment policies establish concentration limits for securities and prohibit the purchase of securities issued by AEP (with the exception of proportionate and immaterial holdings of AEP securities in passive index strategies or certain commingled funds). However, the investment policies do not preclude the benefit trust funds from receiving contributions in the form of AEP securities, provided that the AEP securities acquired by each plan may not exceed the limitations imposed by law.

For equity investments, the concentration limits are generally as follows:

- No security in excess of 5% of all equities.
- Cash equivalents must be less than 10% of an investment manager's equity portfolio.
- No individual stock may be more than 10% and 7% for pension and OPEB investments, respectively, of each manager's equity portfolio.
- No securities may be bought or sold on margin or other use of leverage.

For fixed income investments, each investment manager's portfolio is compared to investment grade, diversified long and intermediate benchmark indices.

A portion of the pension assets is invested in real estate funds to provide diversification, add return and hedge against inflation. Real estate properties are illiquid, difficult to value and not actively traded. The pension plan uses external real estate investment managers to invest in commingled funds that hold real estate properties. To mitigate investment risk in the real estate portfolio, commingled real estate funds are used to ensure that holdings are diversified by region, property type and risk classification. Real estate holdings include core, value-added and opportunistic classifications.

A portion of the pension assets is invested in private equity. Private equity investments add return and provide diversification and typically require a long-term time horizon to evaluate investment performance. Private equity is classified as an alternative investment because it is illiquid, difficult to value and not actively traded. The pension plan uses limited partnerships and commingled funds to invest across the private equity investment spectrum. The private equity holdings are with multiple general partners who help monitor the investments and provide investment selection expertise. The holdings are currently comprised of venture capital, buyout and hybrid debt and equity investments.

AEP participates in a securities lending program with BNY Mellon to provide incremental income on idle assets and to provide income to offset custody fees and other administrative expenses. AEP lends securities to borrowers approved by BNY Mellon in exchange for collateral. All loans are collateralized by at least 102% of the loaned asset's market value and the collateral is invested. The difference between the rebate owed to the borrower and the collateral rate of return determines the earnings on the loaned security. The securities lending program's objective is to provide modest incremental income with a limited increase in risk. As of December 31, 2019 and 2018, the fair value of securities on loan as part of the program was $246 million and $241 million, respectively. Cash and securities obtained as collateral exceeded the fair value of the securities loaned as of December 31, 2019 and 2018.

Trust owned life insurance (TOLI) underwritten by The Prudential Insurance Company is held in the OPEB plan trusts. The strategy for holding life insurance contracts in the taxable Voluntary Employees' Beneficiary Association trust is to minimize taxes paid on the asset growth in the trust. Earnings on plan assets are tax-deferred within the TOLI contract and can be tax-free if held until claims are paid. Life insurance proceeds remain in the trust and are used to fund future retiree medical benefit liabilities. With consideration to other investments held in the trust, the cash value of the TOLI contracts is invested in two diversified funds. A portion is invested in a commingled fund with underlying investments in stocks that are actively traded on major international equity exchanges. The other portion of the TOLI cash value is invested in a diversified, commingled fixed income fund with underlying investments in government bonds, corporate bonds and asset-backed securities.

Cash and cash equivalents are held in each trust to provide liquidity and meet short-term cash needs. Cash equivalent funds are used to provide diversification and preserve principal. The underlying holdings in the cash funds are investment grade money market instruments including commercial paper, certificates of deposit, treasury bills and other types of investment grade short-term debt securities. The cash funds are valued each business day and provide daily liquidity.

Nuclear Trust Funds (Applies to AEP and I&M)

Nuclear decommissioning and SNF trust funds represent funds that regulatory commissions allow I&M to collect through rates to fund future decommissioning and SNF disposal liabilities. By rules or orders, the IURC, the MPSC and the FERC established investment limitations and general risk management guidelines. In general, limitations include:

- Acceptable investments (rated investment grade or above when purchased).
- Maximum percentage invested in a specific type of investment.
- Prohibition of investment in obligations of AEP, I&M or their affiliates.
- Withdrawals permitted only for payment of decommissioning costs and trust expenses.

I&M maintains trust funds for each regulatory jurisdiction. Regulatory approval is required to withdraw decommissioning funds. These funds are managed by an external investment manager that must comply with the guidelines and rules of the applicable regulatory authorities. The trust assets are invested to optimize the net of tax earnings of the trust giving consideration to liquidity, risk, diversification and other prudent investment objectives.

I&M records securities held in these trust funds in Spent Nuclear Fuel and Decommissioning Trusts on its balance sheets. I&M records these securities at fair value. I&M classifies securities in the trust funds as available-for-sale due to their long-term purpose. With the adoption of ASU 2016-01, effective January 2018, available-for-sale classification only applies to investment in debt securities. Additionally, the adoption of ASU 2016-01 required changes in fair value of equity securities to be recognized in earnings. However, due to the regulatory treatment described below, this is not applicable for I&M's trust fund securities.

Other-than-temporary impairments for investments in debt securities are considered realized losses as a result of securities being managed by an external investment management firm. The external investment management firm makes specific investment decisions regarding the debt and equity investments held in these trusts and generally intends to sell debt securities in an unrealized loss position as part of a tax optimization strategy. Impairments reduce the cost basis of the securities which will affect any future unrealized gain or realized gain or loss due to the adjusted cost of investment. I&M records unrealized gains, unrealized losses and other-than-temporary impairments from securities in these trust funds as adjustments to the regulatory liability account for the nuclear decommissioning trust funds and to regulatory assets or liabilities for the SNF disposal trust funds in accordance with their treatment in rates. Consequently, changes in fair value of trust assets do not affect earnings or AOCI. See the "Nuclear Contingencies" section of Note 6 for additional discussion of nuclear matters. See "Fair Value Measurements of Trust Assets for Decommissioning and SNF Disposal" section of Note 11 for disclosure of the fair value of assets within the trusts.

Comprehensive Income (Loss) (Applies to all Registrants except AEPTCo)

Comprehensive income (loss) is defined as the change in equity (net assets) of a business enterprise during a period from transactions and other events and circumstances from non-owner sources. It includes all changes in equity during a period except those resulting from investments by owners and distributions to owners. Comprehensive income (loss) has two components: net income (loss) and other comprehensive income (loss).

Stock-Based Compensation Plans

As of December 31, 2019, AEP had performance shares and restricted stock units outstanding under the American Electric Power System 2015 Long-Term Incentive Plan (2015 LTIP). Upon vesting, all outstanding performance shares and restricted stock units settle in AEP common stock. Performance units awarded prior to 2017 and restricted stock units granted after January 1, 2013 and prior to January 1, 2017 that vested to executive officers were settled in cash. During 2019, all of the remaining performance units and restricted stock units that settle in cash were settled. The impact of AEP's stock-based compensation plans are insignificant to the financial statements of the Registrant Subsidiaries.

AEP maintains a variety of tax qualified and nonqualified deferred compensation plans for employees and non-employee directors that include, among other options, an investment in or an investment return equivalent to that of AEP common stock. This includes AEP career shares maintained under the American Electric Power System Stock Ownership Requirement Plan (SORP), which facilitates executives in meeting minimum stock ownership requirements assigned to them by the Human Resources Committee of the Board of Directors. AEP career shares are derived from vested performance shares granted to employees under the 2015 LTIP. AEP career shares accrue additional dividend shares in an amount equal to dividends paid on AEP common shares at the closing market price on the dividend payments date. All AEP career shares are settled in shares of AEP common stock after the executive's service with AEP ends.

Performance shares awarded after January 1, 2017 are classified as temporary equity in the Mezzanine Equity section of the balance sheets. These awards may be settled in cash upon an employee's qualifying termination due to a change in control. Because such event is not solely within the control of the company, these awards are classified outside of permanent equity.

AEP compensates their non-employee directors, in part, with stock units under the American Electric Power Company, Inc. Stock Unit Accumulation Plan for Non-Employee Directors. These stock units become payable in cash to directors after their service ends.

Management measures and recognizes compensation expense for all share-based payment awards to employees and directors based on estimated fair values. For share-based payment awards with service only vesting conditions, management recognizes compensation expense on a straight-line basis. Stock-based compensation expense recognized on the statements of income for the years ended December 31, 2019, 2018 and 2017 is based on the number of outstanding awards at the end of each period without a reduction for estimated forfeitures. AEP accounts for forfeitures in the period in which they occur.

For the years ended December 31, 2019, 2018 and 2017, compensation cost is included in Net Income for the performance shares, career shares, restricted stock units and the non-employee director's stock units. Compensation cost may also be capitalized. See Note 15 - Stock-based Compensation for additional information.

Equity Investment in Unconsolidated Entities (Applies to AEP and SWEPCo)

The equity method of accounting is used for equity investments where either AEP or SWEPCo exercise significant influence but do not hold a controlling financial interest. Such investments are initially recorded at cost in Deferred Charges and Other Noncurrent Assets on the balance sheets. The proportionate share of the investee's equity earnings or losses is included in Equity Earnings (Loss) of Unconsolidated Subsidiaries on the statements of income. AEP and SWEPCo regularly monitor and evaluate equity method investments to determine whether they are impaired. An impairment is recorded when the investment has experienced a decline in value that is other-than-temporary in nature.

AEP has various significant equity method investments, which include ETT, DHLC and five wind farms acquired in the purchase of Sempra Renewables LLC. See Note 17 - Variable Interest Entities and Equity Method Investments for additional information.

Earnings Per Share (EPS) (Applies to AEP)

Basic EPS is calculated by dividing net earnings available to common shareholders by the weighted-average number of common shares outstanding during the period. Diluted EPS is calculated by adjusting the weighted-average outstanding common shares, assuming conversion of all potentially dilutive stock options and awards.

The following table presents AEP's basic and diluted EPS calculations included on the statements of income:

	Years Ended December 31,					
	2019		2018		2017	
	(in millions, except per share data)					
		$/share		$/share		$/share
Earnings Attributable to AEP Common Shareholders	$ 1,921.1		$ 1,923.8		$ 1,912.6	
Weighted Average Number of Basic Shares Outstanding	493.7	$ 3.89	492.8	$ 3.90	491.8	$ 3.89
Weighted Average Dilutive Effect of Stock-Based Awards	1.6	(0.01)	1.0	—	0.8	(0.01)
Weighted Average Number of Diluted Shares Outstanding	495.3	$ 3.88	493.8	$ 3.90	492.6	$ 3.88

Equity Units issued in March 2019 are potentially dilutive securities but were excluded from the calculation of diluted EPS for the year ended December 31, 2019, as the dilutive stock price threshold was not met. See Note 14 - Financing Activities for additional information.

There were no antidilutive shares outstanding as of December 31, 2019, 2018 and 2017.

Reclassifications

Certain reclassifications have been made in the 2018 financial statements and notes to conform to the 2019 presentation.

Supplementary Income Statement Information

The following tables provide the components of Depreciation and Amortization for the years ended December 31, 2019, 2018 and 2017:

2019

Depreciation and Amortization	AEP	AEP Texas	AEPTCo	APCo	I&M	OPCo	PSO	SWEPCo
				(in millions)				
Depreciation and Amortization of Property, Plant and Equipment	$ 2,203 7	$ 365 9	$ 176 0	$ 466 5	$ 330.6	$ 229 4	$ 162 5	$ 247 9
Amortization of Certain Securitized Assets	280 7	258 7	—	—	—	22 0	—	—
Amortization of Regulatory Assets and Liabilities	30 1	(2 3)	—	0.3	20.0	(10 5)	7 0	1 2
Total Depreciation and Amortization	$ 2,514.5	$ 622.3	$ 176.0	$ 466.8	$ 350 6	$ 240 9	$ 169 5	$ 249 1

2018

Depreciation and Amortization	AEP	AEP Texas	AEPTCo	APCo	I&M	OPCo	PSO	SWEPCo
				(in millions)				
Depreciation and Amortization of Property, Plant and Equipment	$ 1,965 0	$ 262 2	$ 133.9	$ 428.1	$ 278 9	$ 232 6	$ 155 5	$ 237 0
Amortization of Certain Securitized Assets	287 9	240 0	—	—	—	47 9	—	—
Amortization of Regulatory Assets and Liabilities	33.7	(2.6)	—	0 3	14.2	(20 8)	8 5	2.5
Total Depreciation and Amortization	$ 2,286 6	$ 499 6	$ 133 9	$ 428 4	$ 293.1	$ 259 7	$ 164 0	$ 239 5

2017

Depreciation and Amortization	AEP	AEP Texas	AEPTCo	APCo	I&M	OPCo	PSO	SWEPCo
				(in millions)				
Depreciation and Amortization of Property, Plant and Equipment	$ 1,709.1	$ 221 1	$ 95 7	$ 407 6	$ 203 1	$ 200 9	$ 131 4	$ 217.2
Amortization of Certain Securitized Assets	275.9	231 4	—	—	—	44.4	—	—
Amortization of Regulatory Assets and Liabilities	12.2	(2.4)	—	0.3	7 8	(19.4)	(1 0)	0 2
Total Depreciation and Amortization	$ 1,997 2	$ 450 1	$ 95 7	$ 407 9	$ 210 9	$ 225.9	$ 130 4	$ 217 4

Supplementary Cash Flow Information (Applies to AEP)

Cash Flow Information	Years Ended December 31, 2019	2018	2017
		(in millions)	
Cash Paid (Received) for.			
Interest, Net of Capitalized Amounts	$ 1,022.5	$ 939 3	$ 858.3
Income Taxes	6.1	(24 7)	(1.1)
Noncash Investing and Financing Activities.			
Acquisitions Under Finance Leases	87.5	55 6	60 7
Construction Expenditures Included in Current Liabilities as of December 31,	1,341.1	1,120.4	1,330 8
Construction Expenditures Included in Noncurrent Liabilities as of December 31,	—	—	71.8
Acquisition of Nuclear Fuel Included in Current Liabilities as of December 31,	0.1	4.0	—
Noncash Contribution of Assets by Noncontrolling Interest	—	84.0	—
Expected Reimbursement for Spent Nuclear Fuel Dry Cask Storage	0 3	2 2	2.6
Noncontrolling Interest Assumed with Sempra Renewables LLC and Santa Rita East Acquisition	253.4	—	—
Liabilities Assumed with Sempra Renewable LLC and Santa Rita East Acquisition	32.4	—	—

2. NEW ACCOUNTING STANDARDS

The disclosures in this note apply to all Registrants unless indicated otherwise.

During the FASB's standard-setting process and upon issuance of final standards, management reviews the new accounting literature to determine its relevance, if any, to the Registrants' business. The following standards will impact the financial statements.

ASU 2016-02 "Accounting for Leases" (ASU 2016-02)

In February 2016, the FASB issued ASU 2016-02 increasing the transparency and comparability among organizations by recognizing lease assets and lease liabilities on the balance sheets and disclosing key information about leasing arrangements. Under the new standard, an entity must recognize an asset and liability for operating leases on the balance sheets. Additionally, capital leases are known as finance leases going forward. Leases with terms of 12 months or longer are also subject to the new requirements. Fundamentally, the criteria used to determine lease classification remains the same, but is more subjective under the new standard.

New leasing standard implementation activities included the identification of the lease population within the AEP System as well as the sampling of representative lease contracts to analyze accounting treatment under the new accounting guidance. Based upon the completed assessments, management also prepared a gap analysis to outline new disclosure compliance requirements.

Management adopted ASU 2016-02 effective January 1, 2019 by means of a cumulative-effect adjustment to the balance sheets. Management elected the following practical expedients upon adoption:

Practical Expedient	Description
Overall Expedients (for leases commenced prior to adoption date and must be adopted as a package)	Do not need to reassess whether any expired or existing contracts are/or contain leases, do not need to reassess the lease classification for any expired or existing leases and do not need to reassess initial direct costs for any existing leases.
Lease and Non-lease Components (elect by class of underlying asset)	Elect as an accounting policy to not separate non-lease components from lease components and instead account for each lease and associated non-lease component as a single lease component
Short-term Lease (elect by class of underlying asset)	Elect as an accounting policy to not apply the recognition requirements to short-term leases
Existing and expired land easements not previously accounted for as leases	Elect optional transition practical expedient to not evaluate under Topic 842 existing or expired land easements that were not previously accounted for as leases under the current leases guidance in Topic 840
Cumulative-effect adjustment in the period of adoption	Elect the optional transition practical expedient to adopt the new lease requirements through a cumulative-effect adjustment on the balance sheets in the period of adoption

Management concluded that the result of adoption would not materially change the volume of contracts that qualify as leases going forward. The adoption of the new standard did not materially impact results of operations or cash flows, but did have a material impact on the balance sheets. See Note 13 - Leases for additional disclosures required by the new standard.

ASU 2016-13 "Measurement of Credit Losses on Financial Instruments" (ASU 2016-13)

In June 2016, the FASB issued ASU 2016-13 requiring the recognition of an allowance for expected credit losses for financial instruments within its scope. Examples of financial instruments that are in scope include trade receivables, certain financial guarantees, and held-to-maturity debt securities. The allowance for expected credit losses should be based on historical information, current conditions and reasonable and supportable forecasts. Entities are required to evaluate, and if necessary, recognize expected credit losses at the inception or initial acquisition of a financial instrument (or pool of financial instruments that share similar risk characteristics) subject to ASU 2016-13, and subsequently as of each reporting date. The new standard also revises the other-than-temporary impairment model for available-for-sale debt securities.

Management adopted ASU 2016-13 and its related implementation guidance effective January 1, 2020, by means of a cumulative-effect adjustment to the balance sheets. The adoption of the new standard did not have a material impact to financial position, and had no impact on the results of operations or cash flows. Additionally, the adoption of the new standard did not result in any changes to current accounting systems.

Implementation activities included: (1) the identification and evaluation of the population of financial instruments within the AEP system that are subject to the new standard and, (2) the development of supporting valuation models to also contemplate appropriate metrics for current and supportable forecasted information. As required by ASU 2016-13, the financial instruments subject to the new standard were evaluated on a pool-basis to the extent such financial instruments shared similar risk characteristics.

Management continues to develop disclosures to comply with the requirements of ASU 2016-13 that are required in the first quarter of 2020. Management will continue to monitor for any potential industry implementation issues.

3. COMPREHENSIVE INCOME

The disclosures in this note apply to all Registrants except for AEPTCo. AEPTCo does not have any components of other comprehensive income for any period presented in the financial statements.

Presentation of Comprehensive Income

The following tables provide the components of changes in AOCI and details of reclassifications from AOCI for the years ended December 31, 2019, 2018 and 2017. The amortization of pension and OPEB AOCI components are included in the computation of net periodic pension and OPEB costs. See Note 8 - Benefit Plans for additional details.

AEP

	Cash Flow Hedges		Pension and OPEB		
For the Year Ended December 31, 2019	**Commodity**	**Interest Rate**	**Amortization of Deferred Costs**	**Changes in Funded Status**	**Total**
			(in millions)		
Balance in AOCI as of December 31, 2018	$ (23.0)	$ (12.6)	$ 136 3	$ (221.1)	$ (120 4)
Change in Fair Value Recognized in AOCI	(127 2)	(0 2) (a)	—	57 7	(69 7)
Amount of (Gain) Loss Reclassified from AOCI					
Generation & Marketing Revenues (b)	(0 2)	—	—	—	(0 2)
Purchased Electricity for Resale (b)	59.5	—	—	—	59 5
Interest Expense (b)	—	1 5	—	—	1 5
Amortization of Prior Service Cost (Credit)	—	—	(19.2)	—	(19.2)
Amortization of Actuarial (Gains) Losses	—	—	12 1	—	12.1
Reclassifications from AOCI, before Income Tax (Expense) Benefit	59 3	1 5	(7 1)	—	53 7
Income Tax (Expense) Benefit	12 6	0 2	(1.5)	—	11 3
Reclassifications from AOCI, Net of Income Tax (Expense) Benefit	46.7	1 3	(5 6)	—	42 4
Net Current Period Other Comprehensive Income (Loss)	(80 5)	1.1	(5 6)	57 7	(27 3)
Balance in AOCI as of December 31, 2019	$ (103 5)	$ (11 5)	$ 130 7	$ (163 4)	$ (147 7)

AEP

For the Year Ended December 31, 2018	Cash Flow Hedges			Pension and OPEB		
	Commodity	Interest Rate	Securities Available for Sale	Amortization of Deferred Costs	Changes in Funded Status	Total
			(in millions)			
Balance in AOCI as of December 31, 2017	$ (28.4)	$ (13.0)	$ 11.9	$ 141.6	$ (179.9)	$ (67.8)
Change in Fair Value Recognized in AOCI	37.3	2.3	—	—	(33.0)	6.6
Amount of (Gain) Loss Reclassified from AOCI						
Generation & Marketing Revenues (b)	(0.1)	—	—	—	—	(0.1)
Purchased Electricity for Resale (b)	(32.6)	—	—	—	—	(32.6)
Interest Expense (b)	—	1.1	—	—	—	1.1
Amortization of Prior Service Cost (Credit)	—	—	—	(19.5)	—	(19.5)
Amortization of Actuarial (Gains) Losses	—	—	—	12.8	—	12.8
Reclassifications from AOCI, before Income Tax (Expense) Benefit	(32.7)	1.1	—	(6.7)	—	(38.3)
Income Tax (Expense) Benefit	(6.9)	0.3	—	(1.4)	—	(8.0)
Reclassifications from AOCI, Net of Income Tax (Expense) Benefit	(25.8)	0.8	—	(5.3)	—	(30.3)
Net Current Period Other Comprehensive Income (Loss)	11.5	3.1	—	(5.3)	(33.0)	(23.7)
ASU 2018-02 Adoption	(6.1)	(2.7)	—	—	(8.2)	(17.0)
ASU 2016-01 Adoption	—	—	(11.9)	—	—	(11.9)
Balance in AOCI as of December 31, 2018	$ (23.0)	$ (12.6)	$ —	$ 136.3	$ (221.1)	$ (120.4)

For the Year Ended December 31, 2017	Cash Flow Hedges			Pension and OPEB		
	Commodity	Interest Rate	Securities Available for Sale	Amortization of Deferred Costs	Changes in Funded Status	Total
			(in millions)			
Balance in AOCI as of December 31, 2016	$ (23.1)	$ (15.7)	$ 8.4	$ 140.5	$ (266.4)	$ (156.3)
Change in Fair Value Recognized in AOCI	(20.4)	1.6	3.5	—	86.5	71.2
Amount of (Gain) Loss Reclassified from AOCI						
Generation & Marketing Revenues (b)	(5.6)	—	—	—	—	(5.6)
Purchased Electricity for Resale (b)	28.8	—	—	—	—	28.8
Interest Expense (b)	—	1.5	—	—	—	1.5
Amortization of Prior Service Cost (Credit)	—	—	—	(19.6)	—	(19.6)
Amortization of Actuarial (Gains) Losses	—	—	—	21.3	—	21.3
Reclassifications from AOCI, before Income Tax (Expense) Benefit	23.2	1.5	—	1.7	—	26.4
Income Tax (Expense) Benefit	8.1	0.4	—	0.6	—	9.1
Reclassifications from AOCI, Net of Income Tax (Expense) Benefit	15.1	1.1	—	1.1	—	17.3
Net Current Period Other Comprehensive Income (Loss)	(5.3)	2.7	3.5	1.1	86.5	88.5
Balance in AOCI as of December 31, 2017	$ (28.4)	$ (13.0)	$ 11.9	$ 141.6	$ (179.9)	$ (67.8)

AEP Texas

For the Year Ended December 31, 2019	Cash Flow Hedge – Interest Rate	Pension and OPEB: Amortization of Deferred Costs	Pension and OPEB: Changes in Funded Status	Total
		(in millions)		
Balance in AOCI as of December 31, 2018	$ (4.4)	$ 4.7	$ (15.4)	$ (15.1)
Change in Fair Value Recognized in AOCI	—	—	1.1	1.1
Amount of (Gain) Loss Reclassified from AOCI				
Interest Expense (b)	1.3	—	—	1.3
Amortization of Prior Service Cost (Credit)	—	(0.1)	—	(0.1)
Amortization of Actuarial (Gains) Losses	—	0.3	—	0.3
Reclassifications from AOCI, before Income Tax (Expense) Benefit	1.3	0.2	—	1.5
Income Tax (Expense) Benefit	0.3	—	—	0.3
Reclassifications from AOCI, Net of Income Tax (Expense) Benefit	1.0	0.2	—	1.2
Net Current Period Other Comprehensive Income (Loss)	1.0	0.2	1.1	2.3
Balance in AOCI as of December 31, 2019	$ (3.4)	$ 4.9	$ (14.3)	$ (12.8)

For the Year Ended December 31, 2018	Cash Flow Hedge – Interest Rate	Pension and OPEB: Amortization of Deferred Costs	Pension and OPEB: Changes in Funded Status	Total
		(in millions)		
Balance in AOCI as of December 31, 2017	$ (4.5)	$ 4.5	$ (12.6)	$ (12.6)
Change in Fair Value Recognized in AOCI	—	—	(1.0)	(1.0)
Amount of (Gain) Loss Reclassified from AOCI				
Interest Expense (b)	1.3	—	—	1.3
Amortization of Prior Service Cost (Credit)	—	(0.1)	—	(0.1)
Amortization of Actuarial (Gains) Losses	—	0.4	—	0.4
Reclassifications from AOCI, before Income Tax (Expense) Benefit	1.3	0.3	—	1.6
Income Tax (Expense) Benefit	0.3	0.1	—	0.4
Reclassifications from AOCI, Net of Income Tax (Expense) Benefit	1.0	0.2	—	1.2
Net Current Period Other Comprehensive Income (Loss)	1.0	0.2	(1.0)	0.2
ASU 2018-02 Adoption	(0.9)	—	(1.8)	(2.7)
Balance in AOCI as of December 31, 2018	$ (4.4)	$ 4.7	$ (15.4)	$ (15.1)

For the Year Ended December 31, 2017	Cash Flow Hedge – Interest Rate	Pension and OPEB: Amortization of Deferred Costs	Pension and OPEB: Changes in Funded Status	Total
		(in millions)		
Balance in AOCI as of December 31, 2016	$ (5.4)	$ 4.2	$ (13.7)	$ (14.9)
Change in Fair Value Recognized in AOCI	—	—	1.1	1.1
Amount of (Gain) Loss Reclassified from AOCI				
Interest Expense (b)	1.3	—	—	1.3
Amortization of Prior Service Cost (Credit)	—	(0.1)	—	(0.1)
Amortization of Actuarial (Gains) Losses	—	0.5	—	0.5
Reclassifications from AOCI, before Income Tax (Expense) Benefit	1.3	0.4	—	1.7
Income Tax (Expense) Benefit	0.4	0.1	—	0.5
Reclassifications from AOCI, Net of Income Tax (Expense) Benefit	0.9	0.3	—	1.2
Net Current Period Other Comprehensive Income (Loss)	0.9	0.3	1.1	2.3
Balance in AOCI as of December 31, 2017	$ (4.5)	$ 4.5	$ (12.6)	$ (12.6)

APCo

For the Year Ended December 31, 2019	Cash Flow Hedge – Interest Rate	Pension and OPEB: Amortization of Deferred Costs	Pension and OPEB: Changes in Funded Status	Total
		(in millions)		
Balance in AOCI as of December 31, 2018	$ 1.8	$ 11.7	$ (18.5)	$ (5.0)
Change in Fair Value Recognized in AOCI	—	—	13.4	13.4
Amount of (Gain) Loss Reclassified from AOCI				
Interest Expense (b)	(1.1)	—	—	(1.1)
Amortization of Prior Service Cost (Credit)	—	(5.3)	—	(5.3)
Amortization of Actuarial (Gains) Losses	—	2.1	—	2.1
Reclassifications from AOCI, before Income Tax (Expense) Benefit	(1.1)	(3.2)	—	(4.3)
Income Tax (Expense) Benefit	(0.2)	(0.7)	—	(0.9)
Reclassifications from AOCI, Net of Income Tax (Expense) Benefit	(0.9)	(2.5)	—	(3.4)
Net Current Period Other Comprehensive Income (Loss)	(0.9)	(2.5)	13.4	10.0
Balance in AOCI as of December 31, 2019	$ 0.9	$ 9.2	$ (5.1)	$ 5.0

For the Year Ended December 31, 2018	Cash Flow Hedges: Commodity	Cash Flow Hedges: Interest Rate	Pension and OPEB: Amortization of Deferred Costs	Pension and OPEB: Changes in Funded Status	Total
			(in millions)		
Balance in AOCI as of December 31, 2017	$ —	$ 2.2	$ 14.8	$ (15.7)	$ 1.3
Change in Fair Value Recognized in AOCI	(0.7)	—	—	(2.6)	(3.3)
Amount of (Gain) Loss Reclassified from AOCI					
Purchased Electricity for Resale (b)	0.9	—	—	—	0.9
Interest Expense (b)	—	(1.1)	—	—	(1.1)
Amortization of Prior Service Cost (Credit)	—	—	(5.2)	—	(5.2)
Amortization of Actuarial (Gains) Losses	—	—	1.3	—	1.3
Reclassifications from AOCI, before Income Tax (Expense) Benefit	0.9	(1.1)	(3.9)	—	(4.1)
Income Tax (Expense) Benefit	0.2	(0.2)	(0.8)	—	(0.8)
Reclassifications from AOCI, Net of Income Tax (Expense) Benefit	0.7	(0.9)	(3.1)	—	(3.3)
Net Current Period Other Comprehensive Income (Loss)	—	(0.9)	(3.1)	(2.6)	(6.6)
ASU 2018-02 Adoption	—	0.5	—	(0.2)	0.3
Balance in AOCI as of December 31, 2018	$ —	$ 1.8	$ 11.7	$ (18.5)	$ (5.0)

For the Year Ended December 31, 2017	Cash Flow Hedge – Interest Rate	Pension and OPEB: Amortization of Deferred Costs	Pension and OPEB: Changes in Funded Status	Total
		(in millions)		
Balance in AOCI as of December 31, 2016	$ 2.9	$ 16.0	$ (27.3)	$ (8.4)
Change in Fair Value Recognized in AOCI	—	—	11.6	11.6
Amount of (Gain) Loss Reclassified from AOCI				
Interest Expense (b)	(1.1)	—	—	(1.1)
Amortization of Prior Service Cost (Credit)	—	(5.2)	—	(5.2)
Amortization of Actuarial (Gains) Losses	—	3.4	—	3.4
Reclassifications from AOCI, before Income Tax (Expense) Benefit	(1.1)	(1.8)	—	(2.9)
Income Tax (Expense) Benefit	(0.4)	(0.6)	—	(1.0)
Reclassifications from AOCI, Net of Income Tax (Expense) Benefit	(0.7)	(1.2)	—	(1.9)
Net Current Period Other Comprehensive Income (Loss)	(0.7)	(1.2)	11.6	9.7
Balance in AOCI as of December 31, 2017	$ 2.2	$ 14.8	$ (15.7)	$ 1.3

I&M

For the Year Ended December 31, 2019	Cash Flow Hedge – Interest Rate	Pension and OPEB: Amortization of Deferred Costs	Pension and OPEB: Changes in Funded Status	Total
		(in millions)		
Balance in AOCI as of December 31, 2018	$ (11.5)	$ 5.1	$ (7.4)	$ (13.8)
Change in Fair Value Recognized in AOCI	—	—	0.8	0.8
Amount of (Gain) Loss Reclassified from AOCI				
Interest Expense (b)	2.0	—	—	2.0
Amortization of Prior Service Cost (Credit)	—	(0.8)	—	(0.8)
Amortization of Actuarial (Gains) Losses	—	0.6	—	0.6
Reclassifications from AOCI, before Income Tax (Expense) Benefit	2.0	(0.2)	—	1.8
Income Tax (Expense) Benefit	0.4	—	—	0.4
Reclassifications from AOCI, Net of Income Tax (Expense) Benefit	1.6	(0.2)	—	1.4
Net Current Period Other Comprehensive Income (Loss)	1.6	(0.2)	0.8	2.2
Balance in AOCI as of December 31, 2019	$ (9.9)	$ 4.9	$ (6.6)	$ (11.6)

For the Year Ended December 31, 2018	Cash Flow Hedge – Interest Rate	Pension and OPEB: Amortization of Deferred Costs	Pension and OPEB: Changes in Funded Status	Total
		(in millions)		
Balance in AOCI as of December 31, 2017	$ (10.7)	$ 5.1	$ (6.5)	$ (12.1)
Change in Fair Value Recognized in AOCI	—	—	(0.6)	(0.6)
Amount of (Gain) Loss Reclassified from AOCI				
Interest Expense (b)	2.0	—	—	2.0
Amortization of Prior Service Cost (Credit)	—	(0.8)	—	(0.8)
Amortization of Actuarial (Gains) Losses	—	0.8	—	0.8
Reclassifications from AOCI, before Income Tax (Expense) Benefit	2.0	—	—	2.0
Income Tax (Expense) Benefit	0.4	—	—	0.4
Reclassifications from AOCI, Net of Income Tax (Expense) Benefit	1.6	—	—	1.6
Net Current Period Other Comprehensive Income (Loss)	1.6	—	(0.6)	1.0
ASU 2018-02 Adoption	(2.4)	—	(0.3)	(2.7)
Balance in AOCI as of December 31, 2018	$ (11.5)	$ 5.1	$ (7.4)	$ (13.8)

For the Year Ended December 31, 2017	Cash Flow Hedge – Interest Rate	Pension and OPEB: Amortization of Deferred Costs	Pension and OPEB: Changes in Funded Status	Total
		(in millions)		
Balance in AOCI as of December 31, 2016	$ (12.0)	$ 5.1	$ (9.3)	$ (16.2)
Change in Fair Value Recognized in AOCI	—	—	2.8	2.8
Amount of (Gain) Loss Reclassified from AOCI				
Interest Expense (b)	2.0	—	—	2.0
Amortization of Prior Service Cost (Credit)	—	(0.9)	—	(0.9)
Amortization of Actuarial (Gains) Losses	—	0.9	—	0.9
Reclassifications from AOCI, before Income Tax (Expense) Benefit	2.0	—	—	2.0
Income Tax (Expense) Benefit	0.7	—	—	0.7
Reclassifications from AOCI, Net of Income Tax (Expense) Benefit	1.3	—	—	1.3
Net Current Period Other Comprehensive Income (Loss)	1.3	—	2.8	4.1
Balance in AOCI as of December 31, 2017	$ (10.7)	$ 5.1	$ (6.5)	$ (12.1)

OPCo

For the Year Ended December 31, 2019		Cash Flow Hedge – Interest Rate
		(in millions)
Balance in AOCI as of December 31, 2018	$	1.0
Change in Fair Value Recognized in AOCI		—
Amount of (Gain) Loss Reclassified from AOCI		
Interest Expense (b)		(1.3)
Reclassifications from AOCI, before Income Tax (Expense) Benefit		(1.3)
Income Tax (Expense) Benefit		(0.3)
Reclassifications from AOCI, Net of Income Tax (Expense) Benefit		(1.0)
Net Current Period Other Comprehensive Income (Loss)		(1.0)
Balance in AOCI as of December 31, 2019	$	—

For the Year Ended December 31, 2018		Cash Flow Hedge – Interest Rate
		(in millions)
Balance in AOCI as of December 31, 2017	$	1.9
Change in Fair Value Recognized in AOCI		—
Amount of (Gain) Loss Reclassified from AOCI		
Interest Expense (b)		(1.7)
Reclassifications from AOCI, before Income Tax (Expense) Benefit		(1.7)
Income Tax (Expense) Benefit		(0.4)
Reclassifications from AOCI, Net of Income Tax (Expense) Benefit		(1.3)
Net Current Period Other Comprehensive Income (Loss)		(1.3)
ASU 2018-02 Adoption		0.4
Balance in AOCI as of December 31, 2018	$	1.0

For the Year Ended December 31, 2017		Cash Flow Hedge – Interest Rate
		(in millions)
Balance in AOCI as of December 31, 2016	$	3.0
Change in Fair Value Recognized in AOCI		—
Amount of (Gain) Loss Reclassified from AOCI		
Interest Expense (b)		(1.7)
Reclassifications from AOCI, before Income Tax (Expense) Benefit		(1.7)
Income Tax (Expense) Benefit		(0.6)
Reclassifications from AOCI, Net of Income Tax (Expense) Benefit		(1.1)
Net Current Period Other Comprehensive Income (Loss)		(1.1)
Balance in AOCI as of December 31, 2017	$	1.9

PSO

For the Year Ended December 31, 2019	Cash Flow Hedge – Interest Rate
	(in millions)
Balance in AOCI as of December 31, 2018	$ 2.1
Change in Fair Value Recognized in AOCI	—
Amount of (Gain) Loss Reclassified from AOCI	
Interest Expense (b)	(1.3)
Reclassifications from AOCI, before Income Tax (Expense) Benefit	(1.3)
Income Tax (Expense) Benefit	(0.3)
Reclassifications from AOCI, Net of Income Tax (Expense) Benefit	(1.0)
Net Current Period Other Comprehensive Income (Loss)	(1.0)
Balance in AOCI as of December 31, 2019	$ 1.1

For the Year Ended December 31, 2018	Cash Flow Hedge – Interest Rate
	(in millions)
Balance in AOCI as of December 31, 2017	$ 2.6
Change in Fair Value Recognized in AOCI	—
Amount of (Gain) Loss Reclassified from AOCI	
Interest Expense (b)	(1.3)
Reclassifications from AOCI, before Income Tax (Expense) Benefit	(1.3)
Income Tax (Expense) Benefit	(0.3)
Reclassifications from AOCI, Net of Income Tax (Expense) Benefit	(1.0)
Net Current Period Other Comprehensive Income (Loss)	(1.0)
ASU 2018-02 Adoption	0.5
Balance in AOCI as of December 31, 2018	$ 2.1

For the Year Ended December 31, 2017	Cash Flow Hedge – Interest Rate
	(in millions)
Balance in AOCI as of December 31, 2016	$ 3.4
Change in Fair Value Recognized in AOCI	—
Amount of (Gain) Loss Reclassified from AOCI	
Interest Expense (b)	(1.3)
Reclassifications from AOCI, before Income Tax (Expense) Benefit	(1.3)
Income Tax (Expense) Benefit	(0.5)
Reclassifications from AOCI, Net of Income Tax (Expense) Benefit	(0.8)
Net Current Period Other Comprehensive Income (Loss)	(0.8)
Balance in AOCI as of December 31, 2017	$ 2.6

SWEPCo

		Pension and OPEB		
For the Year Ended December 31, 2019	**Cash Flow Hedge – Interest Rate**	**Amortization of Deferred Costs**	**Changes in Funded Status**	**Total**
		(in millions)		
Balance in AOCI as of December 31, 2018	$ (3.3)	$ (0.2)	$ (1 9)	$ (5 4)
Change in Fair Value Recognized in AOCI	—	—	3 7	3.7
Amount of (Gain) Loss Reclassified from AOCI				
Interest Expense (b)	1 9	—	—	1 9
Amortization of Prior Service Cost (Credit)	—	(2 0)	—	(2.0)
Amortization of Actuarial (Gains) Losses	—	0.6	—	0.6
Reclassifications from AOCI, before Income Tax (Expense) Benefit	1 9	(1.4)	—	0.5
Income Tax (Expense) Benefit	0 4	(0 3)	—	0 1
Reclassifications from AOCI, Net of Income Tax (Expense) Benefit	1 5	(1.1)	—	0 4
Net Current Period Other Comprehensive Income (Loss)	1 5	(1.1)	3 7	4 1
Balance in AOCI as of December 31, 2019	$ (1.8)	$ (1.3)	$ 1.8	$ (1 3)

		Pension and OPEB		
For the Year Ended December 31, 2018	**Cash Flow Hedge – Interest Rate**	**Amortization of Deferred Costs**	**Changes in Funded Status**	**Total**
		(in millions)		
Balance in AOCI as of December 31, 2017	$ (6 0)	$ 1.2	$ 0 8	$ (4 0)
Change in Fair Value Recognized in AOCI	2 3	—	(3 1)	(0 8)
Amount of (Gain) Loss Reclassified from AOCI				
Interest Expense (b)	2.1	—	—	2 1
Amortization of Prior Service Cost (Credit)	—	(2.0)	—	(2.0)
Amortization of Actuarial (Gains) Losses	—	0 2	—	0 2
Reclassifications from AOCI, before Income Tax (Expense) Benefit	2.1	(1 8)	—	0 3
Income Tax (Expense) Benefit	0 4	(0 4)	—	—
Reclassifications from AOCI, Net of Income Tax (Expense) Benefit	1 7	(1.4)	—	0.3
Net Current Period Other Comprehensive Income (Loss)	4 0	(1 4)	(3 1)	(0 5)
ASU 2018-02 Adoption	(1 3)	—	0.4	(0.9)
Balance in AOCI as of December 31, 2018	$ (3.3)	$ (0.2)	$ (1.9)	$ (5 4)

		Pension and OPEB		
For the Year Ended December 31, 2017	**Cash Flow Hedge – Interest Rate**	**Amortization of Deferred Costs**	**Changes in Funded Status**	**Total**
		(in millions)		
Balance in AOCI as of December 31, 2016	$ (7 4)	$ 1 9	$ (3 9)	$ (9.4)
Change in Fair Value Recognized in AOCI	—	—	4 7	4 7
Amount of (Gain) Loss Reclassified from AOCI				
Interest Expense (b)	2 2	—	—	2 2
Amortization of Prior Service Cost (Credit)	—	(2 0)	—	(2 0)
Amortization of Actuarial (Gains) Losses	—	0.9	—	0.9
Reclassifications from AOCI, before Income Tax (Expense) Benefit	2 2	(1 1)	—	1 1
Income Tax (Expense) Benefit	0 8	(0.4)	—	0 4
Reclassifications from AOCI, Net of Income Tax (Expense) Benefit	1 4	(0 7)	—	0 7
Net Current Period Other Comprehensive Income (Loss)	1 4	(0 7)	4.7	5.4
Balance in AOCI as of December 31, 2017	$ (6 0)	$ 1.2	$ 0.8	$ (4.0)

(a) The change in fair value includes $4 million related to AEP's investment in joint venture wind farms acquired as part of the purchase of Sempra Renewables LLC for the year ended December 31, 2019 See "Sempra Renewables LLC" section of Note 17 for additional information
(b) Amounts reclassified to the referenced line item on the statements of income

4. RATE MATTERS

The disclosures in this note apply to all Registrants unless indicated otherwise.

The Registrants are involved in rate and regulatory proceedings at the FERC and their state commissions. Rate matters can have a material impact on net income, cash flows and possibly financial condition. The Registrants' recent significant rate orders and pending rate filings are addressed in this note.

Impact of Tax Reform

Rate and regulatory matters are impacted by federal income tax implications. In December 2017, Tax Reform was enacted, which impacts outstanding rate and regulatory matters. For additional details on the impact of Tax Reform, see Note 12 - Income Taxes.

AEP Texas Rate Matters (Applies to AEP and AEP Texas)

2019 Texas Base Rate Case

In May 2019, AEP Texas filed a request with the PUCT for a $56 million annual increase in rates based upon a proposed 10.5% return on common equity. The filing includes a proposed Income Tax Refund Rider that will refund $21 million annually of Excess ADIT that is primarily not subject to normalization requirements. The rate case also seeks a prudence determination on all transmission and distribution capital additions through 2018 included in interim rates from 2008 to December 2019. As of December 31, 2019, AEP Texas' cumulative revenues from transmission and distribution interim rate increases are estimated to be approximately $1.4 billion and are subject to reconciliation in this base rate case.

In November 2019, ALJs issued a Proposal for Decision recommending a $60 million annual rate reduction based upon a 9.4% return on common equity. The ALJs also recommended disallowances that could potentially result in write-offs of $84 million related to capital incentives and $5 million related to other plant additions. Additionally, the ALJs recommended that AEP Texas should be required to file an application for a separate proceeding to determine if any refunds are required associated with any disallowances on distribution or transmission capital investments.

In February 2020, AEP Texas, the PUCT staff and various intervenors filed a stipulation and settlement agreement with the PUCT. The agreement includes a proposed annual base rate reduction of $40 million based upon a 9.4% return on common equity with a capital structure of 57.5% debt and 42.5% common equity. The agreement provides recovery of $26 million in capitalized vegetation management expenses that were incurred through 2018. The agreement includes disallowances of $23 million related to capital investments recorded through 2018 and $4 million related to rate case expenses. In addition, AEP Texas will refund: (a) $77 million of Excess ADIT and excess federal income taxes collected as a result of Tax Reform to distribution customers over a one year period, (b) $31 million of Excess ADIT and excess federal income taxes collected as a result of Tax Reform to transmission customers as a one-time credit and (c) $30 million of previously collected rates that were subject to reconciliation in this proceeding over a one year period with no carrying costs. Per the agreement, AEP Texas is required to file its next base rate case within four years of the date of the final order. The agreement also: (a) states future financially based capital incentives will not be included in interim transmission and distribution rates, (b) contains various ring-fencing provisions and (c) will allow the PUCT to decide whether to adopt a dividend restriction ring-fencing provision.

As a result of the stipulation and settlement agreement, AEP Texas (a) recorded an impairment of $33 million in December 2019 related to capital investments, which included $10 million of current year investments, in Asset Impairments and Other Related Charges on the statements of income, (b) recorded a $30 million provision for refund on the statements of income for revenues previously collected through rates and (c) wrote-off $4 million of rate case expenses to Other Operation on the statements of income. The PUCT is expected to issue an order in the first quarter of 2020. Upon approval of the 2019 Texas Base Rate Case, AEP Texas will refund $275 million of Excess ADIT associated with certain depreciable property using ARAM to transmission customers. AEP Texas will determine how to refund the remaining Excess ADIT that is not subject to normalization requirements in future proceedings. If the final order from the PUCT requires refunds or authorizes disallowances in excess of the amounts included within the February 2020 stipulation and settlement agreement, it could reduce future net income and cash flows and impact financial condition.

Texas Storm Cost Securitization

In August 2017, Hurricane Harvey hit the coast of Texas, causing power outages in the AEP Texas service territory. In March 2019, AEP Texas filed a request to securitize total estimated distribution-related system restoration costs with the PUCT, which included estimated carrying costs. In June 2019, the PUCT approved the financing order. As part of the financing order, AEP Texas agreed to offset $64 million of Excess ADIT that is not subject to normalization requirements against the total distribution-related system restoration costs. In September 2019, AEP Texas issued $235 million of securitization bonds. The securitization bonds included carrying costs of $33 million, which includes $21 million of debt carrying costs recorded as a reduction to Interest Expense in 2019.

The stipulation and settlement agreement discussed in the 2019 Texas Base Rate Case above does not require any adjustments to the remaining $95 million of estimated net transmission-related system restoration costs and these costs will be recovered in base rates if the agreement is approved by the PUCT. If these costs are not recovered, it could have an adverse effect on future net income, cash flows and financial condition.

APCo and WPCo Rate Matters (Applies to AEP and APCo)

Virginia Legislation Affecting Earnings Reviews

Under a 2015 amended Virginia law, APCo's existing generation and distribution base rates were frozen until after the Virginia SCC ruled on APCo's next biennial review. The 2015 amendments also precluded the Virginia SCC from performing biennial reviews of APCo's earnings for the years 2014 through 2017.

Further amendments to Virginia law impacting investor-owned utilities were enacted, effective July 1, 2018, that require APCo to file its next generation and distribution base rate case by March 31, 2020 using 2017, 2018 and 2019 earnings test years (triennial review). Triennial reviews are subject to an earnings test which provides that 70% of any earnings in excess of 70 basis points above APCo's Virginia SCC authorized ROE would be refunded to customers. In such case, the Virginia SCC could also lower APCo's Virginia retail base rates on a prospective basis. In November 2018, the Virginia SCC authorized a ROE of 9.42% applicable to APCo base rate earnings for the 2017-2019 triennial period.

Virginia law provides that costs associated with asset impairments of retired coal generation assets, or automated meters, or both, which a utility records as an expense, shall be attributed to the test periods under review in a triennial review proceeding, and be deemed recovered. In 2015, APCo retired the Sporn Plant, the Kanawha River Plant, the Glen Lyn Plant, Clinch River Unit 3 and the coal portions of Clinch River Units 1 and 2 (collectively, the retired coal-fired generation assets). The net book value of these plants at the retirement date was $93 million before cost of removal, including materials and supplies inventory. Based on management's interpretation of Virginia law and more certainty regarding APCo's triennial revenues, expenses and resulting earnings upon reaching the end of the three-year review period, APCo recorded a pretax expense of $93 million related to its previously retired coal-fired generation assets in December 2019. This expense is included in Asset Impairments and Other Related Charges on the statements of income. As a result, management deems these costs to be substantially recovered by APCo during the triennial review period.

APCo is currently in the process of retiring and replacing its Virginia jurisdictional Automated Meter Reading (AMR) meters with Advanced Metering Infrastructure (AMI) meters. As of December 31, 2019, APCo has approximately $51 million of Virginia jurisdictional AMR meters recorded in Total Property, Plant and Equipment - Net on its balance sheets. APCo intends to pursue full recovery of these assets through future depreciation rates.

Inclusive of the $93 million expense associated with APCo's Virginia jurisdictional retired coal-fired plants, APCo estimates its Virginia earnings for the triennial period to be below the authorized ROE range. If any APCo Virginia jurisdictional costs are not recoverable or refunds of revenues collected from customers during the triennial review period, it could reduce future net income and cash flows and impact financial condition.

Virginia Staff Depreciation Study Request

In November 2018, Virginia staff recommended that APCo implement new Virginia jurisdictional depreciation rates effective January 1, 2018 based on APCo's depreciation study that was prepared at Virginia staff's request using December 31, 2017 APCo property balances. Implementation of those depreciation rates would result in a $21 million pretax increase in annual depreciation expense ($6 million related to transmission) with no corresponding increase in retail base rates. In December 2018, APCo submitted a response to the Virginia staff stating that it was inappropriate for APCo to change Virginia depreciation rates in advance of the Virginia SCC's Triennial Review of APCo's earnings, citing the Virginia SCC's November 2014 order to not change APCo's Virginia depreciation rates until APCo's next base rate case/review. If the Virginia SCC were to issue an order approving the Virginia staff's recommended retroactive change in APCo's Virginia depreciation rates, it would reduce future net income and cash flows and impact financial condition.

Virginia Tax Reform

In March 2019, the Virginia SCC issued an order to reduce APCo's base rates to refund: (a) $40 million annually for ongoing annual tax savings, (b) $9 million annually of Excess ADIT associated with certain depreciable property using ARAM, (c) $94 million of Excess ADIT that is not subject to normalization requirements over three years and (d) a one-time credit of $22 million for estimated excess taxes collected from customers as a result of Tax Reform during the 15-month period ending March 31, 2019.

2018 West Virginia Base Rate Case

In May 2018, APCo and WPCo filed a joint request with the WVPSC to increase their combined West Virginia base rates by $115 million ($98 million related to APCo) annually based on a 10.22% return on common equity. The proposed annual increase included $32 million ($28 million related to APCo) due to increased annual depreciation expense and reflected the impact of the reduction in the federal income tax rate due to Tax Reform. In October 2018, APCo and WPCo filed updated schedules supporting a $95 million ($80 million related to APCo) annual increase in West Virginia base rates primarily due to the impact of West Virginia Tax Reform.

In February 2019, the WVPSC issued an order approving a stipulation and settlement agreement between APCo, WPCo, WVPSC staff and certain intervenors. The agreement included an annual base rate increase of $44 million ($36 million related to APCo) based upon a 9.75% return on common equity effective March 2019. The agreement also included: (a) $18 million ($14 million related to APCo) of increased annual depreciation expense, (b) a $24 million refund ($19 million related to APCo) over two years, through a rider beginning March 2019, of Excess ADIT that is not subject to normalization requirements, (c) the utilization of $14 million ($12 million related to APCo) of Excess ADIT that is not subject to normalization requirements to offset regulatory asset balances relating to ENEC, (d) an agreement to seek WVPSC approval of economic incentive programs to provide funds to aid in industrial and commercial development and (e) an agreement, barring any unforeseen events, to not initiate another base rate proceeding prior to April 1, 2020.

ETT Rate Matters (Applies to AEP)

ETT Interim Transmission Rates

AEP has a 50% equity ownership interest in ETT. Predominantly all of ETT's revenues are based on semi-annual interim rate changes which are subject to review and possible true-up in the next base rate proceeding. Through December 31, 2019, AEP's share of ETT's cumulative revenues that are subject to review is estimated to be $1 billion. A base rate review could produce a refund if ETT incurs a disallowance of the transmission investment on which an interim increase was based. A revenue decrease, including a refund of interim transmission rates, could reduce future net income and cash flows and impact financial condition. Management is unable to determine a range of potential losses, if any, that are reasonably possible of occurring.

In 2018, the PUCT adopted a rule requiring investor-owned utilities operating solely inside ERCOT to make periodic filings for base rate proceedings. The rule requires ETT to file for a comprehensive base rate review no later than February 1, 2021.

I&M Rate Matters (Applies to AEP and I&M)

Michigan Tax Reform

In October 2018, I&M made a filing with the MPSC recommending to: (a) refund Excess ADIT associated with certain depreciable property using ARAM and (b) refund Excess ADIT that is not subject to normalization requirements over ten years. In November 2019, the MPSC issued an order authorizing I&M to: (a) refund $48 million of Excess ADIT associated with certain depreciable property using ARAM and (b) refund $28 million of Excess ADIT that is not subject to normalization requirements over ten years. In January 2020, the MPSC issued an order in the 2019 Michigan Base Rate Case that changed the refund period from ten years to five years. See "2019 Michigan Base Rate Case" below.

2019 Indiana Base Rate Case

In May 2019, I&M filed a request with the IURC for a $172 million annual increase. The requested increase in Indiana rates would be phased in through January 2021 and is based upon a proposed 10.5% return on common equity. The proposed annual increase includes $78 million related to a proposed annual increase in depreciation expense. The requested annual increase in depreciation expense includes $52 million related to proposed investments and $26 million related to increased depreciation rates. The request includes the continuation of all existing riders and a new Automated Metering Infrastructure (AMI) rider for proposed meter projects.

In August 2019, various intervenors filed testimony that recommended annual rate increases ranging from $2 million to $33 million based upon a return on common equity ranging from 9% to 9.73%. The difference between I&M's requested annual base rate increase and the intervenor's recommendations are primarily due to: (a) proposed denial of return on and of certain new plant investments, (b) proposed lower depreciation rates, (c) a reduction in the requested return on common equity and (d) exclusion of I&M's proposed re-allocation of capacity costs related to I&M's June 2020 loss of a significant FERC wholesale contract. In addition, certain intervenors recommended disallowances that could potentially result in write-offs of $41 million related to the remaining book value of existing Indiana jurisdictional meters if I&M is approved to deploy AMI meters as initially requested and $11 million associated with certain Cook Plant study costs.

In September 2019, I&M filed testimony rebutting the various intervenors' recommendations. In October 2019, a hearing at the IURC was held. The IURC is expected to issue an order on this case in the first quarter of 2020. If any of these costs are not recoverable, it could reduce future net income and cash flows and impact financial condition.

2019 Michigan Base Rate Case

In June 2019, I&M filed a request with the MPSC for a $58 million annual increase. The requested increase in Michigan rates would be phased in through June 2020 and is based upon a proposed 10.5% return on common equity. The proposed annual increase includes $19 million related to a proposed annual increase in depreciation expense. The requested annual increase in depreciation expense includes $13 million related to proposed investments and $6 million related to increased depreciation rates. The proposed annual increase also includes $10 million for annual lost revenue related to the Michigan Electric Customer Choice Program that began in 2019.

In January 2020, the MPSC issued an order approving a stipulation and settlement agreement authorizing an annual base rate increase of $36 million based upon a 9.86% return on common equity effective with the first billing cycle of February 2020. The order also requires I&M to amortize and refund to customers through I&M Michigan base rates: (a) Excess ADIT that is not subject to normalization (over a period of five years starting February 2020) and (b) Excess ADIT associated with certain depreciable property using ARAM. Additionally, the order states that I&M will not be allowed to file its next base rate case before 2022.

OPCo Rate Matters (Applies to AEP and OPCo)

Ohio ESP Filings

In 2016, OPCo filed a proposal to extend the ESP through May 2024. In April 2018, the PUCO issued an order approving the ESP extension stipulation agreement, with no significant changes. In October 2018, an intervenor filed an appeal with the Ohio Supreme Court challenging various approved riders. In January 2020, the Ohio Supreme Court affirmed the PUCO order, rejecting the filed appeal.

OPCo's Enhanced Service Reliability Rider (ESRR) authorized under the ESP is subject to annual audits. In May 2018, the PUCO staff filed comments indicating that 2016 spending under the ESRR was subject to authorized limits and that OPCo overspent those limits. In March 2019, the PUCO staff filed additional comments that OPCo overspent the authorized limit in 2017. Management believes that both 2016 and 2017 ESRR spending is not subject to an authorized limit and that a spending limit was not established until 2018, as part of the ESP extension. A hearing was held in May 2019 to address the 2016 audit. In December 2019, the PUCO issued an order finding that OPCo's 2016 ESRR spending was not subject to an authorized limit. If it is determined OPCo did have an authorized spending limit under the ESRR in 2017, and refunds are ordered, it would reduce future net income and cash flows and impact financial condition.

2016 SEET Filing

Ohio law provides for the return of significantly excessive earnings to ratepayers upon PUCO review. Significantly excessive earnings are measured by whether the earned return on common equity of the electric utility is significantly in excess of the return on common equity that was earned during the same period by publicly traded companies, including utilities, that face comparable business and financial risk.

In 2016, OPCo recorded a 2016 SEET provision of $58 million based upon projected earnings data for companies in the comparable utilities risk group. In determining OPCo's return on equity in relation to the comparable utilities risk group, management excluded the following items resolved in OPCo's Global Settlement that was filed at the PUCO in December 2016 and subsequently approved in February 2017: (a) gain on the deferral of Retail Stability Rider costs, (b) refunds to customers related to the SEET remands and (c) refunds to customers related to fuel adjustment clause proceedings.

In February 2019, the PUCO issued an order that OPCo did not have significantly excessive earnings in 2016. As a result of the order, OPCo reversed the $58 million provision in the first quarter of 2019.

<u>PSO Rate Matters</u> (Applies to AEP and PSO)

2018 Oklahoma Base Rate Case

In 2018, PSO filed a request with the OCC for an $88 million annual increase in Oklahoma retail rates based upon a 10.3% return on common equity. PSO also proposed to implement a performance-based rate plan that combines a formula rate with a set of customer-focused performance incentive measures related to reliability, public safety, customer satisfaction and economic development. The proposed annual increase included $13 million related to increased annual depreciation rates and $7 million related to increased storm expense amortization. The requested increase in annual depreciation rates included the recovery of Oklaunion Power Station through 2028 (currently being recovered in rates through 2046). Management has announced plans to retire Oklaunion Power Station by October 2020.

In March 2019, the OCC issued an order approving a stipulation and settlement agreement for a $46 million annual increase, based on a 9.4% return on equity effective with the first billing cycle of April 2019. The order also included agreements between the parties that: (a) depreciation rates will remain unchanged, (b) PSO will file a new base rate request no earlier than October 2020 and no later than October 2021 and (c) PSO will refund Excess ADIT that is not subject to normalization requirements over five years instead of the ten years ordered in the Oklahoma Tax Reform case. The order did not approve the performance-based rate plan but instead provided for an expansion of the SPP Transmission Tariff that tracks previously untracked SPP costs and a new Distribution Reliability and Safety Rider that provides additional revenues capped at $5 million per year for distribution projects related to safety and reliability that are not normal distribution replacements.

<u>SWEPCo Rate Matters</u> (Applies to AEP and SWEPCo)

2012 Texas Base Rate Case

In 2012, SWEPCo filed a request with the PUCT to increase annual base rates primarily due to the completion of the Turk Plant. In 2013, the PUCT issued an order affirming the prudence of the Turk Plant but determined that the Turk Plant's Texas jurisdictional capital cost cap established in a previous Certificate of Convenience and Necessity case also limited SWEPCo's recovery of AFUDC in addition to limits on its recovery of cash construction costs.

Upon rehearing in 2014, the PUCT reversed its initial ruling and determined that AFUDC was excluded from the Turk Plant's Texas jurisdictional capital cost cap. As a result, SWEPCo reversed $114 million of a previously recorded regulatory disallowance in 2013. The resulting annual base rate increase was approximately $52 million. In 2017, the Texas District Court upheld the PUCT's 2014 order and intervenors filed appeals with the Texas Third Court of Appeals.

In July 2018, the Texas Third Court of Appeals reversed the PUCT's judgment affirming the prudence of the Turk Plant and remanded the issue back to the PUCT. In January 2019, SWEPCo and the PUCT filed petitions for review with the Texas Supreme Court. In May 2019, various intervenors filed replies to the petition. In July 2019, SWEPCo filed its response to these replies. In the fourth quarter of 2019 and first quarter of 2020, SWEPCo and various intervenors filed briefs with the Texas Supreme Court.

As of December 31, 2019, the net book value of Turk Plant was $1.5 billion, before cost of removal, including materials and supplies inventory and CWIP. If certain parts of the PUCT order are overturned and if SWEPCo cannot ultimately fully recover its approximate 33% Texas jurisdictional share of the Turk Plant investment, including AFUDC, it could reduce future net income and cash flows and impact financial condition.

2016 Texas Base Rate Case

In 2016, SWEPCo filed a request with the PUCT for a net increase in Texas annual revenues of $69 million based upon a 10% return on common equity. In January 2018, the PUCT issued a final order approving a net increase in Texas annual revenues of $50 million based upon a return on common equity of 9.6%, effective May 2017. The final order also included: (a) approval to recover the Texas jurisdictional share of environmental investments placed in- service, as of June 30, 2016, at various plants, including Welsh Plant, Units 1 and 3, (b) approval of recovery of, but no return on, the Texas jurisdictional share of the net book value of Welsh Plant, Unit 2, (c) approval of $2 million in additional vegetation management expenses and (d) the rejection of SWEPCo's proposed transmission cost recovery mechanism.

As a result of the final order, in 2017 SWEPCo: (a) recorded an impairment charge of $19 million, which included $7 million associated with the lack of return on Welsh Plant, Unit 2 and $12 million related to other disallowed plant investments, (b) recognized $32 million of additional revenues, for the period of May 2017 through December 2017, that was surcharged to customers in 2018 and (c) recognized an additional $7 million of expenses consisting primarily of depreciation expense and vegetation management expense, offset by the deferral of rate case expense. SWEPCo implemented new rates in February 2018 billings. The $32 million of additional 2017 revenues was collected during 2018. In March 2018, the PUCT clarified and corrected portions of the final order, without changing the overall decision or amounts of the rate change. The order has been appealed by various intervenors. If certain parts of the PUCT order are overturned, it could reduce future net income and cash flows and impact financial condition.

2018 Louisiana Formula Rate Filing

In April 2018, SWEPCo filed its formula rate plan for test year 2017 with the LPSC. The filing included a net $28 million annual increase, which was effective August 2018 and included SWEPCo's Louisiana jurisdictional share of Welsh Plant and Flint Creek Plant environmental controls. The filing also included a reduction in the federal income tax rate due to Tax Reform but did not address the return of Excess ADIT benefits to customers.

In July 2018, SWEPCo made a supplemental filing to its formula rate plan with the LPSC to reduce the requested annual increase to $18 million. The difference between SWEPCo's requested $28 million annual increase and the $18 million annual increase in the supplemental filing is primarily the result of the return of Excess ADIT benefits to customers.

In October 2018, the LPSC staff issued a recommendation that SWEPCo refund $11 million of excess federal income taxes collected, as a result of Tax Reform, from January 1, 2018 through July 31, 2018. In June 2019, the LPSC staff issued its report which reaffirmed its $11 million refund recommendation. The report also contends that SWEPCo's requested annual rate increase of $18 million, which was implemented in August 2018, is overstated by $4 million and proposes an annual rate increase of $14 million. Additionally, the report recommends SWEPCo refund the excess over-collections associated with the $4 million difference for the period of August 2018 through the implementation of new rates. In July 2019, the LPSC approved the $11 million refund. A decision by the LPSC on the remaining formula rate plan issues is expected in the first half of 2020.

If any of these costs are not recoverable, it could reduce future net income and cash flows and impact financial condition.

Welsh Plant - Environmental Impact

Management currently estimates that the investment necessary to meet environmental regulations for Welsh Plant, Units 1 and 3 could total approximately $520 million, excluding AFUDC. As of December 31, 2019, SWEPCo had incurred costs of $399 million, including AFUDC, related to these projects. SWEPCo has received approval to recover $340 million of its in-service investments related to environmental controls installed at Welsh Plant through base rates in its Arkansas, Louisiana and Texas jurisdictions. SWEPCo also recovers a portion of its investments related to environmental controls installed at Welsh Plant through wholesale formula rates. See "2016 Texas Base Rate Case," "2018 Louisiana Formula Rate Filing" and "2019 Arkansas Base Rate Case" disclosures for additional information. SWEPCo will seek recovery of future costs that have not yet been approved through base rate cases. If any of the remaining costs are not recoverable, it could reduce future net income and cash flows and impact financial condition.

2019 Arkansas Base Rate Case

In February 2019, SWEPCo filed a request with the APSC for a $75 million increase in Arkansas base rates based upon a proposed 10.5% return on common equity. The filing requested rate base treatment for the Stall Plant and environmental retrofits that were being recovered through riders. Eliminating these riders would result in a net annual requested base rate increase of $58 million. The proposed net annual increase included $12 million related to vegetation management to improve the reliability of its Arkansas distribution system. The filing also provided notice of SWEPCo's proposal to have its rates regulated under the formula rate review mechanism authorized by Arkansas law, including a Formula Rate Review Rider. In October 2019, SWEPCo reduced its requested base rate increase from $75 million to $67 million.

In December 2019, the APSC issued an order approving a stipulation and settlement agreement authorizing an annual base rate increase of $53 million ($24 million net of amounts currently recovered through riders) based upon a 9.45% return on common equity. The order modified the stipulation and settlement agreement and included a disallowance of $4 million for previously recorded capital incentives. The base rate increase includes $6 million for increased annual depreciation expense and became effective with the first billing cycle in January 2020. The order provides recovery for: (a) the Stall Plant, (b) environmental retrofit projects and (c) the remaining net book value, with a debt return for investors, of Welsh Unit 2. The order also states that SWEPCo's rates will be regulated under the formula rate mechanism authorized by Arkansas law, which includes a Formula Rate Review Rider. Additionally, SWEPCo agreed to make the necessary filings with the APSC, at least 12 months in advance, to seek regulatory approval to retire the Dolet Hills Power Station no later than December 31, 2026.

FERC Rate Matters

FERC Transmission Complaint - AEP's PJM Participants (Applies to AEP, AEPTCo, APCo, I&M and OPCo)

In 2016, seven parties filed a complaint at the FERC that alleged the base return on common equity used by AEP's transmission owning subsidiaries within PJM in calculating formula transmission rates under the PJM OATT is excessive and should be reduced from 10.99% to 8.32%, effective upon the date of the complaint. In March 2018, AEP's transmission owning subsidiaries within PJM and six of the complainants filed a settlement agreement with the FERC (the seventh complainant abstained). The settlement agreement: (a) established a base ROE for AEP's transmission owning subsidiaries within PJM of 9.85% (10.35% inclusive of the RTO incentive adder of 0.5%), effective January 1, 2018, (b) required AEP's transmission owning subsidiaries within PJM to provide a one-time refund of $50 million, attributable from the date of the complaint through December 31, 2017, which was credited to customer bills in the second quarter of 2018 and (c) increased the cap on the equity portion of the capital structure to 55% from 50%. As part of the settlement agreement, AEP's transmission owning subsidiaries within PJM also filed updated transmission formula rates incorporating the reduction in the corporate federal income tax rate due to Tax Reform, effective January 1, 2018 and providing for the amortization of the portion of the Excess ADIT that is not subject to normalization requirements over a ten-year period through credits to the federal income tax expense component of the revenue requirement. In May 2019, the FERC approved the settlement agreement.

FERC Transmission Complaint - AEP's SPP Participants (Applies to AEP, AEPTCo, PSO and SWEPCo)

In 2017, several parties filed a complaint at the FERC that states the base return on common equity used by AEP's transmission owning subsidiaries within SPP in calculating formula transmission rates under the SPP OATT is excessive and should be reduced from 10.7% to 8.36%, effective upon the date of the complaint through September 5, 2018. In September 2018, the same parties filed another complaint at the FERC that states the base return on common equity used by AEP's transmission owning subsidiaries within SPP in calculating formula transmission rates under the SPP OATT is excessive and should be reduced from 10.7% to 8.71%, effective upon the date of the second complaint. In June 2019, the FERC approved an unopposed settlement agreement between AEP's transmission owning subsidiaries within SPP and the complainants. The settlement agreement established a base ROE of 10% (10.50% inclusive of the RTO incentive adder of 0.5%) effective January 1, 2019. Additionally, refunds including carrying charges were made from the date of the first complaint through December 31, 2018. Refunds for the period prior to 2019 were made at the time of the 2019 true-up of 2018 rates. Refunds from January 2019 onward will conclude with the 2020 true-up of 2019 rates.

Modifications to AEP's SPP Transmission Rates (Applies to AEP, AEPTCo, PSO and SWEPCo)

In 2017, AEP's transmission owning subsidiaries within SPP filed an application at the FERC to modify the SPP OATT formula transmission rate calculation, including an adjustment to recover a tax-related regulatory asset and a shift from historical to projected expenses. The modified SPP OATT formula rates are based on projected calendar year financial activity and projected plant balances. The FERC accepted the proposed modifications effective January 1, 2018, subject to refund. In February 2019, AEP's transmission owning subsidiaries within SPP filed an uncontested settlement agreement with the FERC resolving all outstanding issues. In June 2019, the FERC approved the settlement agreement.

5. EFFECTS OF REGULATION

The disclosures in this note apply to all Registrants unless indicated otherwise.

Regulated Generating Units to be Retired (Applies to AEP, PSO and SWEPCo)

In September 2018, management announced that the Oklaunion Power Station is probable of abandonment and is to be retired by October 2020. See "2018 Oklahoma Base Rate Case" for additional information.

In January 2020, management announced that the Dolet Hills Power Station is probable of abandonment and is to be retired by December 2026. See "Dolet Hills Lignite Company Operations" section of Executive Overview, "2019 Arkansas Base Rate Case" section of Note 4, and "DHLC" section of Note 17 for additional information.

The table below summarizes the plant investments and their cost of removal, currently being recovered, as well as regulatory assets for accelerated depreciation for the generating units as of December 31, 2019.

Plant	Gross Investment	Accumulated Depreciation	Net Investment	Accelerated Depreciation Regulatory Asset	Materials and Supplies	Cost of Removal Regulatory Liability	Expected Retirement Date	Remaining Recovery Period
				(dollars in millions)				
Oklaunion Power Station	$ 106.7	$ 86.6	$ 20.1	$ 27.4 (a)	$ 3.2	$ 5.1	2020	27 years
Dolet Hills Power Station	338.9	194.2	144.7	— (b)	5.8	23.6	2026	27 years

(a) In October 2018, PSO changed depreciation rates to utilize the 2020 end-of-life and defer depreciation expense to a regulatory asset for the amount in excess of the previously OCC-approved depreciation rates for Oklaunion Power Station. See "2018 Oklahoma Base Rate Case" section of Note 4 for additional information.
(b) Beginning in January 2020, SWEPCo began recording a regulatory asset for accelerated depreciation.

Dolet Hills Power Station and Related Fuel Operations (Applies to AEP and SWEPCo)

During the second quarter of 2019, the Dolet Hills Power Station initiated a seasonal operating schedule. In January 2020, in accordance with the terms of SWEPCo's settlement of its base rate review filed with the APSC, management announced that SWEPCo will seek regulatory approval to retire the Dolet Hills Power Station by the end of 2026. Management also continues to monitor the economic viability of the Dolet Hills Power Station and DHLC mining operations, which may result in a decision to seek permission from appropriate regulatory agencies to discontinue operations earlier than 2026.

The Dolet Hills Power Station costs are recoverable by SWEPCo through base rates. SWEPCo's share of the net investment in the Dolet Hills Power Station is $157 million, including CWIP and materials and supplies, before cost of removal.

Fuel costs incurred by the Dolet Hills Power Station are recoverable by SWEPCo through active fuel clauses. Under the Lignite Mining Agreement, DHLC bills SWEPCo its proportionate share of incurred lignite extraction and associated mining-related costs as fuel is delivered. As of December 31, 2019, DHLC has unbilled fixed costs of $106 million that will be billed to SWEPCo prior to the closure of the Dolet Hills Power Station. In 2009, SWEPCo acquired interests in the Oxbow Lignite Company (Oxbow), which owns mineral rights and leases land. Under a Joint Operating Agreement pertaining to the Oxbow mineral rights and land leases, Oxbow bills SWEPCo its proportionate share of incurred costs. As of December 31, 2019, Oxbow has unbilled fixed costs of $22 million that will be billed to SWEPCo prior to the closure of the Dolet Hills Power Station. Additional operational and land-related costs are expected to be incurred by DHLC and Oxbow and billed to SWEPCo prior to the closure of the Dolet Hills Power Station and recovered through fuel clauses.

If any of these costs are not recoverable, it could reduce future net income and cash flows and impact financial condition.

Regulatory Assets and Liabilities

Regulatory assets and liabilities are comprised of the following items:

	AEP		
	December 31,		Remaining
	2019	2018	Recovery Period
Current Regulatory Assets	(in millions)		
Under-recovered Fuel Costs - earns a return	$ 44.7	$ 101.7	1 year
Under-recovered Fuel Costs - does not earn a return	48 2	48 4	1 year
Total Current Regulatory Assets	$ 92 9	$ 150 1	
Noncurrent Regulatory Assets			
Regulatory assets pending final regulatory approval:			
Regulatory Assets Currently Earning a Return			
Plant Retirement Costs - Unrecovered Plant	$ 35 2	$ 50.3	
Kentucky Deferred Purchased Power Expenses	30 2	14.5	
Oklaunion Power Station Accelerated Depreciation	27 4	5 5	
Other Regulatory Assets Pending Final Regulatory Approval	0 7	9.3	
Total Regulatory Assets Currently Earning a Return	93 5	79.6	
Regulatory Assets Currently Not Earning a Return			
Plant Retirement Costs - Asset Retirement Obligation Costs	30 1	35.3	
Vegetation Management Program - AEP Texas (a)	29.4	—	
Cook Plant Study Costs	7 6	—	
Storm-Related Costs (b)	7 2	152 4	
Asset Retirement Obligation - Louisiana	7 2	5 3	
Other Regulatory Assets Pending Final Regulatory Approval	6 7	15 4	
Total Regulatory Assets Currently Not Earning a Return	88 2	208 4	
Total Regulatory Assets Pending Final Regulatory Approval (c)	181 7	288.0	
Regulatory assets approved for recovery:			
Regulatory Assets Currently Earning a Return			
Plant Retirement Costs - Unrecovered Plant	690 5	680.9	23 years
Plant Retirement Costs - Asset Retirement Obligation Costs	87.4	64.3	21 years
Meter Replacement Costs	65.4	74 4	8 years
Environmental Control Projects	41 0	43 4	21 years
Cook Plant Uprate Project	32 6	35 0	14 years
Ohio Distribution Decoupling	31 4	12 3	2 years
Advanced Metering System	26 5	45 3	2 years
Storm-Related Costs	21 3	31 1	3 years
Mitchell Plant Transfer - West Virginia	16 2	17 0	21 years
Deferred Cook Plant Life Cycle Management Project Costs - Michigan	15 1	16 1	15 years
Cook Plant Turbine	13 4	15 8	19 years
Ohio Capacity Deferral	—	57.8	
Other Regulatory Assets Approved for Recovery	48 4	46 1	various
Total Regulatory Assets Currently Earning a Return	1,089 2	1,139.5	

Regulatory Assets Currently Not Earning a Return			
Pension and OPEB Funded Status	1,309.8	1,326.6	11 years
Unamortized Loss on Reacquired Debt	129.0	134.2	29 years
Unrealized Loss on Forward Commitments	106.8	104.6	13 years
Cook Plant Nuclear Refueling Outage Levelization	63.8	37.5	3 years
Vegetation Management - West Virginia	43.6	26.6	2 years
Postemployment Benefits	34.2	35.6	4 years
Plant Retirement Costs - Asset Retirement Obligation Costs	28.8	21.6	23 years
Medicare Subsidy	23.2	27.9	5 years
Peak Demand Reduction/Energy Efficiency	18.6	31.9	7 years
PJM/SPP Annual Formula Rate True Up	7.3	22.0	2 years
PJM Costs and Off-system Sales Margin Sharing - Indiana	—	20.1	
Other Regulatory Assets Approved for Recovery	122.8	94.3	various
Total Regulatory Assets Currently Not Earning a Return	1,887.9	1,882.9	
Total Regulatory Assets Approved for Recovery	2,977.1	3,022.4	
Total Noncurrent Regulatory Assets	$ 3,158.8	$ 3,310.4	

(a) Includes $26 million of deferred expenses from a stipulation and settlement agreement filed in February 2020. See "2019 Texas Base Rate Case" section of Note 4 - Rate Matters for additional information

(b) In September 2019, AEP Texas securitized $235 million of storm-related costs As a result of the securitization, the regulatory asset balance was transferred to Securitized Assets on the balance sheets. See "Texas Storm Cost Securitization" section of Note 4 - Rate Matters for additional information

(c) In 2015, APCo recorded a $91 million reduction, before cost of removal which was $11 million and $20 million as of December 31, 2019 and 2018, respectively, to Accumulated Depreciation and Amortization related to the remaining net book value of coal plants retired in 2015, primarily related to APCo's Virginia jurisdiction. The net book value of these plants at the retirement date was $93 million before cost of removal, including materials and supplies inventory Based on management's interpretation of Virginia law and more certainty regarding APCo's triennial revenues, expenses and resulting earnings upon reaching the end of the three-year review period, APCo recorded a pretax expense of $93 million related to its previously retired coal-fired generation assets. This expense is included in Asset Impairments and Other Related Charges on the statements of income.

APCo is currently in the process of retiring and replacing its Virginia jurisdictional Automated Meter Reading (AMR) meters with Advanced Metering Infrastructure (AMI) meters As of December 31, 2019, APCo has approximately $51 million of Virginia jurisdictional AMR meters recorded in Total Property, Plant and Equipment - Net on its balance sheets APCo intends to pursue full recovery of these assets through future depreciation rates.

	AEP		
	December 31,		Remaining
	2019	2018	Refund Period
Current Regulatory Liabilities	(in millions)		
Over-recovered Fuel Costs - pays a return	$ 77 5	$ 35.7	1 year
Over-recovered Fuel Costs - does not pay a return	9 1	22 9	1 year
Total Current Regulatory Liabilities	$ 86 6	$ 58.6	
Noncurrent Regulatory Liabilities and Deferred Investment Tax Credits			
Regulatory liabilities pending final regulatory determination:			
Regulatory Liabilities Currently Not Paying a Return			
Other Regulatory Liabilities Pending Final Regulatory Determination	$ 0 2	$ 0.2	
Total Regulatory Liabilities Currently Not Paying a Return	0 2	0 2	
Income Tax Related Regulatory Liabilities (a)			
Excess ADIT Associated with Certain Depreciable Property	571 8	1,025 3	(b)
Excess ADIT that is Not Subject to Rate Normalization Requirements	291 0	695 0	(c) (g)
Total Income Tax Related Regulatory Liabilities	862 8	1,720 3	
Total Regulatory Liabilities Pending Final Regulatory Determination	863 0	1,720 5	
Regulatory liabilities approved for payment:			
Regulatory Liabilities Currently Paying a Return			
Asset Removal Costs	2,876.7	2,742.8	(d)
Ohio Basic Transmission Cost Rider	37 2	68.8	2 years
Excess Earnings	8 3	8.9	34 years
Deferred Investment Tax Credits	6 2	8 7	41 years
Other Regulatory Liabilities Approved for Payment	6 1	8.9	various
Total Regulatory Liabilities Currently Paying a Return	2,934 5	2,838 1	
Regulatory Liabilities Currently Not Paying a Return			
Excess Nuclear Decommissioning Funding	1,236 0	828.5	(e)
Deferred Investment Tax Credits	215.3	204.9	43 years
PJM Transmission Enhancement Refund	67.3	164 2	6 years
Transition and Restoration Charges - Texas	50.5	46 0	10 years
Spent Nuclear Fuel	43 6	42 9	(e)
Ohio Enhanced Service Reliability Plan	29.7	43.1	2 years
Virginia Transmission Rate Adjustment Clause	28 1	11 3	2 years
Deferred Gain on Sale of Rockport Unit 2	27 2	—	3 years
Peak Demand Reduction/Energy Efficiency	23 0	17 5	2 years
Unrealized Gain on Forward Commitments	17 7	45 9	5 years
Other Regulatory Liabilities Approved for Payment	70 0	73 5	various
Total Regulatory Liabilities Currently Not Paying a Return	1,808 4	1,477.8	
Income Tax Related Regulatory Liabilities (a)			
Excess ADIT Associated with Certain Depreciable Property	3,303 0	2,925.7	(f)
Excess ADIT that is Not Subject to Rate Normalization Requirements	890 5	864.3	17 years
Income Taxes Subject to Flow Through	(1,341 8)	(1,286 1)	56 years
Total Income Tax Related Regulatory Liabilities	2,851 7	2,503.9	
Total Regulatory Liabilities Approved for Payment	7,594 6	6,819 8	
Total Noncurrent Regulatory Liabilities and Deferred Investment Tax Credits	$ 8,457 6	$ 8,540 3	

(a) This balance primarily represents regulatory liabilities for Excess ADIT as a result of the reduction in the corporate federal income tax rate from 35% to 21% related to the enactment of Tax Reform The regulatory liability balance predominately pays a return due to the inclusion of Excess ADIT in rate base See "Federal Tax Reform" section of Note 12 for additional information

(b) Includes $275 million that will be refunded using ARAM upon receiving an order in the 2019 Texas Base Rate Case See "2019 Texas Base Rate Case" section of Note 4 - Rate Matters for additional information

(c) Includes $71 million from a stipulation and settlement agreement filed in February 2020. See "2019 Texas Base Rate Case" section of Note 4 - Rate Matters for additional information
(d) Relieved as removal costs are incurred
(e) Relieved when plant is decommissioned.
(f) Refunded using ARAM
(g) 2019 and 2018 amounts include approximately $172 million related to AEP Transmission Holdco's investment in ETT and Transource Energy. AEP Transmission Holdco expects to amortize the balance commensurate with the return of Excess ADIT to ETT and Transource Energy's customers